OPPORTUNITY TO VALUE

2010 ANNUAL REPORT

RICH PORTFOLIO. SOLID EXECUTION.

nexen

What's New in our Annual Filing?

This year, we are filing a Form 40-F in the United States, rather than a Form 10-K. This annual report contains components of that filing, including the Annual Information Form, the MD&A and the Consolidated Financial Statements and Notes. To streamline our disclosure, the corporate governance information previously included in this report is now exclusively in the management proxy circular, and is available at www.nexeninc.com.

Nexen Inc. is an independent, Canadian-based global energy company, listed on the Toronto and New York stock exchanges under the symbol NXY. We are focused on three growth strategies: oil sands and shale gas in Western Canada and conventional exploration and development primarily in the North Sea, offshore West Africa and deep-water Gulf of Mexico. We add value for shareholders through successful full-cycle oil and gas exploration and development, and leadership in ethics, integrity, governance and environmental stewardship.

Rich Portfolio

Recent events have highlighted the benefits of a portfolio with choice. Few predicted the global financial crisis and subsequent decline in oil prices, the collapse in natural gas prices or the unfortunate Gulf of Mexico spill that brought drilling in the basin to a temporary halt.

Our diverse portfolio sustains us through unplanned events such as these. We are in the world's best basins for conventional exploration and development with five significant discoveries in hand. We are in the oil sands with significant resource and a technological advantage that will produce a long-term cost advantage over time. And we're in shale gas, with a massive resource and a long-term strategy to produce it at low cost.

Solid Execution

Translating this opportunity into value requires solid execution and we made great progress in 2010. We advanced each of our three strategies, streamlined our portfolio by selling non-core assets at very favourable prices, and positioned ourselves to bring on 70,000 barrels per day of high-quality production in the next 18 to 24 months. Plus, we have a portfolio of exciting appraisal and exploration opportunities, 22 of which we plan to drill in 2011. We achieved this with safe, secure operations, which deliver some of the highest netbacks in our industry.




From opportunity to value, our three strategies focus on responsibly translating our rich portfolio into high-quality production and earnings.

Our conventional exploration and development business forms the heart of our current production and cash flow. Yemen and Buzzard are two legacy assets, with production also from Canada, the US Gulf of Mexico and Colombia. We are exploring in three of the world's best basins: the North Sea, the deep-water Gulf of Mexico, and offshore West Africa.

Our oil sands properties in Alberta are a legacy asset in the making. As an early mover, we recognized both the value of this vast resource (the world's second largest) and the opportunity to use technology to create a significant cost advantage over time. Long Lake is just the first phase. We have enough resource to keep us busy for decades.

Our shale gas assets in northeast British Columbia are in their infancy, yet hold significant potential to transform our company, given our huge acreage position. In just a few short years we've proven our ability to execute. Now we are expanding each year to gain further efficiencies and deliver good returns.

OUR PORTFOLIO

I believe we have one of the best portfolios around. Its quality and diversity position us well in changing market conditions.

Marvin Romanow, President and Chief Executive Officer

Dear Shareholder:

Events of the past few years, like the global financial crisis, the Gulf of Mexico oil spill or the collapse in natural gas prices have highlighted the benefits of a diversified portfolio in building a sustainable company. Here are attributes that make us resilient and attractive:

High-margin barrels: Much of our production has low operating costs, generating some of the highest netbacks in the industry. We can weather low oil prices and make great returns at current prices. New high-margin projects like Usan and the Golden Eagle area will continue this advantage.

Early-life assets: Half of our conventional production is less than five years old. This means we benefit from modern facilities, plenty of remaining reserves and lower operating costs.

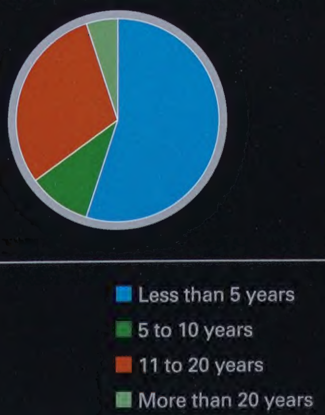
Running room: We have grown our assets over time. In Yemen, we initially expected to produce less than 250 million barrels, yet have produced well over one billion barrels to date. At Buzzard, we've doubled our proved reserves from the time we acquired it. Our portfolio is filled with opportunities to grow current assets and continue exploration.

Blend of long and short cycle times: Although discoveries like Usan and those in the deep-water Gulf of Mexico can span years from discovery to first production, other assets such as our UK tie-back opportunities and shale gas wells can come on stream more quickly and with minimal incremental cost.

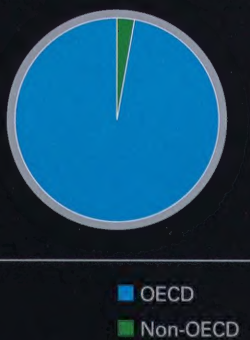
Heavy weighting to oil: With oil currently four times more valuable than gas on an energy equivalent basis, our 80% weighting to oil is a clear advantage. About 80% of our current oil production is indexed to Brent pricing, which has enjoyed a significant premium lately, and is growing in importance as an international benchmark. Yet, we also invested early in shale gas because we believe in natural gas over the long term.

Building a rich portfolio of legacy assets takes time. Our activities in any one year are geared toward advancing our long-term strategies and I believe we made great progress in 2010.

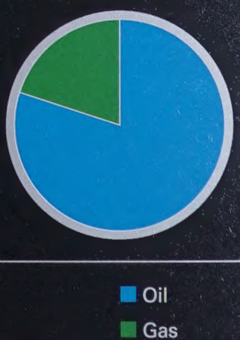
55% of our Conventional Production is Less than Five Years Old



97% of our Portfolio is in OECD Countries

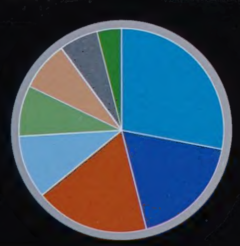


80% of our Portfolio is Oil Weighted



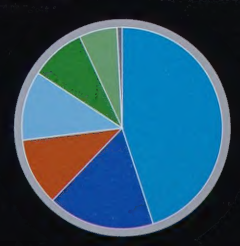
Nexen continued to add key talent in 2010 to support our growth plans.

2010 Capital
$2.7 billion

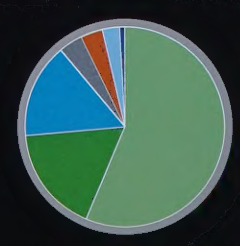


1 Energy Marketing, Corporate, Chemicals and Other

2010 Production before Royalties
246,000 boe/d



2010 Proved + Probable Reserves
2.1 billion boe



In 2010, we met our production guidance and made solid progress in each of our three strategies.

In our conventional business, we added a new discovery at Appomattox, bringing our total to five significant conventional discoveries. We began commissioning the fourth platform at Buzzard, progressed development plans for the Golden Eagle area, and advanced the Usan development, which is on track for first oil in 2012. Our successful 2010 appraisal drilling in the UK generated up to four potential tie-back opportunities and we anticipate more discoveries from exciting exploration prospects (see page iv).

Long Lake has delivered at a slower pace than expected. Yet we've made good progress since our 2009 turnaround, roughly doubling our bitumen production. See page vi for more about how we plan to fill the upgrader and develop our next oil sands phase at Kinosis.

In shale gas, we are executing extremely well. We reduced our capital costs per frac by 65% over one drilling season and significantly expanded our acreage position (see page viii).

Corporately, we streamlined our portfolio by selling non-core assets for excellent value. We sold part of our marketing business that was adding volatility to our earnings and also sold our conventional heavy oil business at market premiums. In early 2011, we also sold our interest in Canexus.

We reduced net debt by approximately $1.5 billion in 2010, primarily from asset dispositions. And our capital program added more reserves than we produced, primarily high-netback barrels in the UK.

All in all, it was a year of solid execution that positions us for significant future growth.

Challenges Build Strength

We also faced challenges. In each case we learned important lessons and took steps to enhance how we work.

In addition to our lower-than-expected production at Long Lake, the unfortunate Macondo blow-out and oil spill shut down drilling in the Gulf of Mexico and delayed our programs. And although we recorded our lowest injury rate ever, we experienced a contractor fatality in Yemen which deeply impacted people throughout Nexen.

These last two events highlight an important point: how we work is critical to our success. Safety, environmental stewardship and corporate governance are not just corporate ideologies. They are part of our core values. That is why they are integral to our everyday lives at Nexen.

Our culture and commitment were recognized in 2010. Once again, we were named one of the Global 100 Most Sustainable Corporations by *Corporate Knights* magazine. I view this as a vote of confidence in our people and the choices we make about how we work.

I admire our employees who tackle challenges and deliver the kind of success we've had this year. I continue to appreciate the support of my management team and board, who believe in our people and see the opportunity in our assets.

I look forward to sharing an exciting 2011 with you.

2010 Highlights	**2010**	2009	2008
Production before Royalties (mboe/d)	**246**	243	250
Production after Royalties (mboe/d)	**220**	213	210
Cash Flow from Operations [1,2] ($ millions)	**2,130**	2,215	4,229
Cash Flow per Share ($/share)	**4.06**	4.25	8.04
Net Income ($ millions)	**1,197**	536	1,715
Net Income per Share ($/share)	**2.28**	1.03	3.26
Cash Netbacks from Oil and Gas Operations [3] ($/boe)	**44.38**	38.55	60.64
Capital Expenditures, Including Acquisitions ($ millions)	**2,702**	3,578	3,203
Proved Reserves [4] (mmboe)	**987**	1,011	988
Proved + Probable Reserves [4] (mmboe)	**2,120**	2,228	2,036

1 Defined as cash flow from operating activities before changes in non-cash working capital and other. 2 For reconciliation of this non-GAAP measure, please see our year-end press release dated February 16, 2011 or our Management's Discussion and Analysis. 3 Defined as average sales price less royalties and other, operating costs and Yemen in-country taxes. 4 After dispositions; represents our working interest before royalties using SEC rules. For more information on our reserves, see our 2010 Annual Information Form at www.nexeninc.com or www.sedar.com.

STRATEGIES IN PROGRESS

CONVENTIONAL EXPLORATION & DEVELOPMENT

We have exceptionally strong assets, tangible production coming and a pipeline of appraisal and exploration opportunities.

High-Grading Over Time

Our portfolio of conventional opportunities is the best it has ever been. Not only are we finding more oil and gas, the size and quality of our discoveries have increased. We did this by upgrading our global portfolio, expanding our land base, adding talent and, most importantly, displaying patience and persistence.

For example, we drilled our first well in the eastern Gulf of Mexico in 2003. It was a modest success. But we persisted and after several exploration wells, we drilled Appomattox with our partner Shell in 2009. I believe this is our best discovery ever in the Gulf, and there's more to come. We look forward to appraising Appomattox and drilling up to three key appraisal and exploration wells in the region in 2011 and 2012.

In the UK, many thought we were making a moderate advance in a mature basin when we acquired Buzzard in 2004. Six years later, we have significantly increased our reserves and are now the second largest oil producer in the UK North Sea.

We built on that success with the Golden Eagle area discovery. Estimated at about 140 million boe of reserves, it's the largest oil discovery in the UK North Sea in the past 10 years, behind only Buzzard. It also highlights our competitive strength in discovering new stratigraphic traps, which are difficult to see on seismic. In the UK, we have high-margin tie-back opportunities to existing infrastructure, some of which we plan to complete in 2011.

Offshore West Africa, Usan is another long-term project that is poised to become a legacy asset after it comes on stream in 2012. We are in a high-quality basin. At full production rates, it will provide a step-change in cash flow. We see plenty of exploration upside in this region, so Usan provides a great platform for future growth.

After almost 20 years of uninterrupted operations, Yemen continues to impress me. Our operations are world class and our commitment to working closely with governments and communities creates real value for stakeholders. In 2011, we're focused on securing a contract extension at Masila and looking to expand our Yemen presence with new exploration blocks.

2011 Plans

We have an exciting capital program planned for 2011. We expect to spend approximately $600 to $650 million on drilling 22 appraisal and exploration wells. Our plans include sanctioning of Golden Eagle and a return to our appraisal and exploration programs in the deep-water Gulf of Mexico now that the moratorium has been lifted.

I believe deep-water drilling in the Gulf of Mexico is safer than ever, because of the lessons learned and new practices put in place following the Macondo incident. At Nexen, we took the opportunity to work with our contractors, regulators and peers to reinforce environmental and safety measures across our offshore operations. We are also managing the financial impact of our rig exposure during the downtime.

With five significant discoveries in hand and more prospects to drill, we see years of continued strength in our conventional business.

We have at least one significant discovery in each core basin:

GULF OF MEXICO:

Appomattox
Knotty Head

OFFSHORE WEST AFRICA:

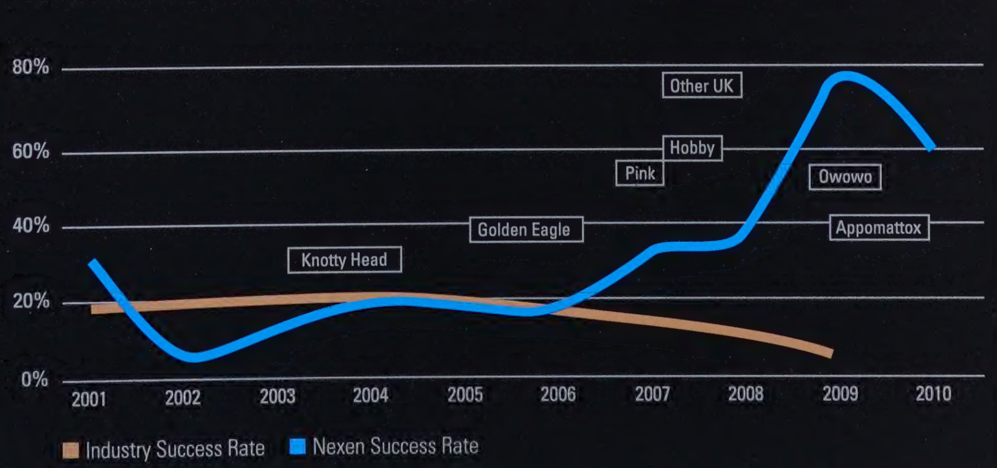
Usan
Owowo

NORTH SEA:

Golden Eagle area

We safely drilled one of the deepest wells in the world at Knotty Head in the Gulf of Mexico.

Exploration Success Improving



When it comes to exploration, there are three key measures:

1. Success rate
2. Size of discovery
3. Quality of discovery

We've improved on all three.

OIL SANDS

With low exploration risk, a massive resource and decades of cash flow coming, we are just beginning in the oil sands.

Making Progress at Long Lake

Long Lake's integrated SAGD and upgrading technology will provide an advantage over time. In retrospect, we underestimated the time it would take to ramp up Long Lake given the complexities in the reservoir, integrating SAGD and the upgrader, and employing ground-breaking technologies on a large scale. We've had challenges, found solutions and are now on the ramp-up curve.

Since our turnaround in the fall of 2009, we've roughly doubled Long Lake production to approximately 30,000 bbls/d gross. We did this by providing more steam to our mature wells, bringing on new well pairs and installing electronic submersible pumps.

As ramp-up of steam continues, we are working our way through high water saturation zones in some parts of the reservoir. This can cause bitumen volumes and steam-oil ratios to vary. Based on our pilot project and subsequent experience, we have found that injecting consistent steam into these zones allows us to progress through them faster. We expect bitumen rates and steam-oil ratios to improve once these zones are heated.

These lean zones are found throughout the oil sands region. As we work our way through them, we are acquiring early and valuable knowledge about how to manage these features, while also looking forward to future phases with higher-quality reservoirs.

Over the next two years, we plan to invest between $400 and $500 million on new well pads, more steam capacity and infrastructure to isolate SAGD from the upgrader, while keeping the benefits of integration. This will allow us to isolate portions of the plant for maintenance with reduced operational impacts. To me, this is money well invested, considering the long-term cash flow our oil sands assets will generate.

The Big Picture

Long Lake represents just 10% of our overall reserves and contingent recoverable oil sands resource, now estimated at three to six billion boe[1]. The resource is there and the technological advantage we've established will grow over time, particularly as natural gas prices increase and heavy oil differentials widen.

We are wiser for having built Long Lake, and will integrate our learnings into future phases. We understand reservoir characteristics and optimizing well performance. We see the benefits of building our oil sands business with smaller incremental projects while still achieving integrated project advantages in the long term. And we understand how to do this while providing isolation between SAGD and the upgrader for operating flexibility and maintenance.

For every problem we've encountered, we've developed a solution. And we've never faced the same problem twice, which is a sign we're on the right track.

Higher-Quality Reservoir at Kinosis

Building on our Long Lake learnings, we plan to stage our capital differently for our second phase. Kinosis will begin as two 35,000-40,000 bbl/d SAGD projects and will be initially fired with natural gas. As Kinosis gets to full ramp-up, and differentials widen according to their traditional long-term cycle, we plan to add an upgrader. Kinosis is a thick, superior quality reservoir with little shale. We will continue core-hole drilling and engineering in 2011 and we expect to be sanction-ready in late 2012.

To be a global energy company, we believe it's important to strategically and responsibly develop the oil sands—the world's second largest hydrocarbon resource.

TECHNOLOGY ADVANTAGE REMAINS

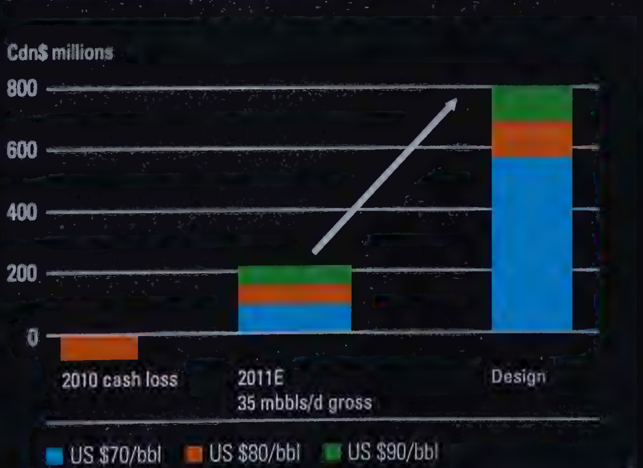
The Long Lake technology:

- **Includes Canada's first gasifier**
- **Transforms a waste product into energy for our operations**
- **Reduces natural gas costs**
- **Produces North America's highest quality crude, which should sell at a premium to WTI**

1 For additional information about our resource estimates, please refer to our November 15, 2010 news release available at www.nexeninc.com.

Long Lake is just the start of our oil sands development plans. We expect to be ready to sanction Kinosis in late 201

Annual Net Cash Flow Expectations



At about 40% up the ramp-up curve at Long Lake, we are breaking even on operating cash flow. The remaining 60% delivers significant cash flow.

At design rates, we expect to generate approximately $800 million annually, assuming WTI of US $90/bbl. I don't know many other projects that are this robust.

In just a few short years, we've done all the right things to build a successful, sustainable shale gas business.

In northeast BC, we've inventoried significant resource potential at pennies per mcf, we're well positioned in a high-quality basin, we've grown our knowledge quickly, and we are executing extremely well. Now we are also looking to take our shale gas expertise to new basins globally and are making modest investments in Colombia and elsewhere.

While gas prices are highly uncertain for the next few years, being a low-cost producer means we can generate decent returns at low prices.

As the chart on the opposite page shows, our execution keeps getting better. Our cost reductions and industry-setting frac pace give us confidence we can make a decent return at US$4/mcf natural gas and a great return at US$6/mcf.

That's why we continued to expand our shale gas position in 2010. We now have more than 300,000 acres in the Horn River, Cordova and Liard basins of northeast BC. We estimate we have between 4 and 15 tcf of contingent recoverable resource at Horn River and Cordova, and 5 to 23 tcf of prospective resource at Liard[1].

Working with Our Stakeholders

Executing well also means working constructively with our stakeholders, including local First Nations. Through the Horn River Basin Producers Group, our industry is taking a coordinated approach to reducing land impacts, improving water use and generating local economic benefits. This approach has served us well in other areas such as Yemen, and I believe it is an essential foundation for building a successful shale gas business.

Our Plans

We're bringing on stream an eight-well pad in the Horn River area that we finished drilling last summer. We've started drilling a nine-well pad that will come on stream in late 2011, and we're planning an 18-well pad for mid 2011, which we expect on stream in late 2012. With 100% interest in our acreage, we are evaluating joint venture options to enable us to realize the value of a portion of this asset.

Longer term, this acreage is potentially an attractive option for liquefied natural gas (LNG) export, given its proximity to the west coast and large, secure resource base. This potential opportunity cannot be ignored, and we will continue to explore it as a long-term option.

Building on Our Expertise

As we look to other emerging unconventional opportunities such as tight oil development in Alberta, we will build on the expertise we've developed in shale gas including horizontal drilling and hydraulic fracturing techniques. I am confident we can apply some of what we've learned in shale gas to continue to grow our unconventional business.

In five to seven years, shale gas could represent 20% of Nexen's production and significantly increase our proved reserves.

NORTHEAST BC OFFERS:

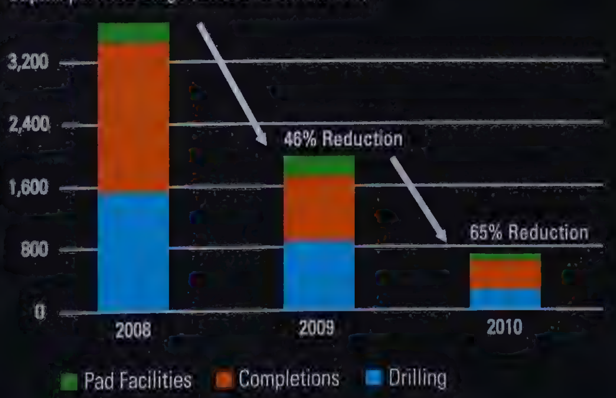
- **Excellent resource density**
- **Good rocks that can be fractured**
- **Good flow rates**
- **Excellent land tenure**
- **A viable LNG option**
- **Attractive fiscal terms**

1 For additional information about our resource estimates, please refer to our November 15, 2010 news release available at www.nexeninc.com.

We were an early mover in BC shale gas and more than doubled our acreage in high-quality areas in 2010.

Executing in BC Shale Gas

Capital per Frac Stage (Cdn$ thousands/frac)



What We Achieved:

- Reduced drilling days from 40 to 25
- Increased well-horizontal length by 80%
- Increased fracs per day to 3.5
- Had 100% success placing sand
- Increased reserves per frac

The result: a 65% decrease in unit cost per frac.

FUTURE GROWTH

We have both near-term catalysts and longer-term growth. And we are executing well to bring these together

Here are our near-term priorities:

- Continue Long Lake ramp-up
- Progress Usan toward first oil in 2012
- Advance and sanction discoveries
- Advance shale gas program
- Secure Yemen contract extension
- Resume exploration and appraisal in Gulf of Mexico
- Continue global exploration

2011 Guidance

In 2011, we plan to invest between $2.4 and $2.7 billion in capital projects. The three largest investments in our plan are approximately $500 million for Usan, $425 million for oil sands and $600 to $650 million for exploration.

We expect production before royalties in the range of 230,000 to 270,000 boe/d. The range is driven by the pace of the Long Lake ramp up, run-times at Buzzard and Scott/Telford, and the timing of new volumes from our North Sea tie-backs and Horn River shale gas program.

At the mid-point of this range, production after royalties would grow by as much as 7%. This continues the robust growth of about 6% on a compound annual basis we have realized over the past five years, after considering the sale of our heavy oil properties. We've also more than replaced our production over this time period with new reserves. Overall, our growing production, solid reserve replacement and strong balance sheet are signs of real progress.

Growth in Hand

Our 2011 plans take us a step closer to delivering more than 70,000 boe/d of new production in the next 18 to 24 months—a step change for our company. Some of this would replace Yemen production in the event we do not receive a contract extension. And with oil being four times more valuable than natural gas, we grow our cash flow faster with an oil-weighted production profile.

Consider alone the cash flow expected from Usan and Long Lake, once at design rates. Together we expect them to generate around $1.4 billion annually at $80/bbl WTI. To put this figure in perspective, that's more than half of the total cash flow we generated in 2010. So, patience pays off.

In the long term, we are well positioned. As the chart on the opposite page shows, we have a solid base of non-declining assets for the next four or five years. This makes it easier to grow our company. A key advantage for Nexen is that we have several growth opportunities already in hand. We have significant oil sands and shale gas resource, and high-quality conventional discoveries to develop.

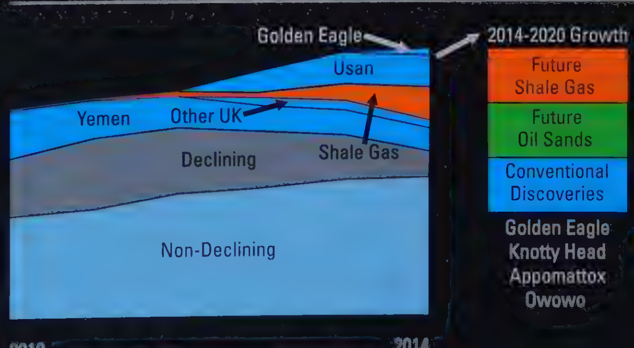
We know what we need to do to translate these opportunities into value, and we're making good progress. And we are always on the lookout for more, leveraging off of what we already know and do well. This is how we build a sustainable company.

We are more than just the Long Lake company or the Yemen company or the Buzzard company. We are a global energy company where every asset adds value.

EXPECTED 2011 CAPITAL	EXPECTED 2011 PRODUCTION	EXPECTED 2011 CASH FLOW
$2.4 to $2.7 billion	230 to 270 mboe/d	$2.1 to $2.8 billion
	before royalties; up to 7% growth at range midpoint	assuming US$75/bbl to US$90/bbl oil

Usan's floating production, storage and offloading unit is due to set sail for offshore West Africa in 2011.

Expected Longer-Term Growth*



* Assumes Yemen contract extension.

Buzzard, Long Lake and Syncrude form a strong production base (in light blue), which is not expected to decline in the next four or five years.

Beyond 2014, we have inventoried sufficient opportunities to stay on trend. Approximately one third are oil sands, one third are shale gas and one third are conventional discoveries, many of which are already in our hands.

PERFORMANCE REVIEW

(Cdn$ millions, except as noted)	2010	2009	2008	2007	2006
Highlights					
Average WTI Oil Price (US$/bbl)	79.52	61.80	99.65	72.31	66.22
Net Sales [1]	5,411	4,203	6,576	5,583	3,936
Cash Flow from Operations [2,3]	2,130	2,215	4,229	3,458	2,669
Per Common Share ($/share)	4.06	4.25	8.04	6.56	5.09
Net Income	1,197	536	1,715	1,086	601
Per Common Share ($/share)	2.28	1.03	3.26	2.06	1.15
Capital Expenditures, Including Acquisitions	2,702	3,578	3,203	3,524	3,536
Proceeds from Dispositions	1,262	17	6	4	27
Production [4,5]					
Production Before Royalties (mboe/d)	246	243	250	254	212
Production After Royalties (mboe/d)	220	213	210	207	156
Financial Position					
Working Capital	1,228	2,398	2,503	412	476
Property, Plant and Equipment, Net	15,249	15,492	14,922	12,498	11,739
Total Assets	21,907	22,900	22,155	18,075	17,156
Net Debt [6]	4,074	5,551	4,575	4,404	4,730
Long-Term Debt	5,079	7,251	6,578	4,610	4,673
Equity [7]	8,791	7,646	7,191	5,610	4,636
Shares and Dividends					
Common Shares Outstanding (millions)	525.7	522.9	519.4	528.3	525.0
Number of Registered Common Shareholders	1,745	1,725	1,624	1,569	1,454
Closing Common Share Price (TSX) (Cdn$/share)	22.80	25.22	21.45	32.10	32.10
Dividends Declared per Common Share (Cdn$/share)	0.20	0.20	0.175	0.10	0.10
Cash Flow from Operations [2,3]					
Oil and Gas					
United Kingdom	2,769	2,159	3,308	2,101	477
Canada	(28)	130	389	179	229
Syncrude	279	192	400	319	240
United States	262	140	508	480	573
Yemen [8]	355	345	638	664	877
Other Countries	15	31	133	87	94
	3,652	2,997	5,376	3,830	2,490
Marketing	(45)	256	(356)	73	432
Chemicals	61	102	85	90	83
	3,668	3,355	5,105	3,993	3,005
Interest and Other Corporate Items	(572)	(512)	(292)	(350)	(254)
Income Taxes	(966)	(628)	(584)	(185)	(82)
Total Cash Flow from Operations	2,130	2,215	4,229	3,458	2,669

1 Represents net sales from continuing operations.
2 Cash flow from operations is defined as cash generated from operating activities before changes in non-cash working capital and other.
3 For reconciliation of this non-GAAP measure, please see our year-end press release dated February 16, 2011 or our Management's Discussion and Analysis.
4 Production is Nexen's working interest share and includes our share of production from Syncrude.
5 Natural gas is converted at 6 mcf per equivalent barrel of oil.
6 Net debt is defined as long-term debt and short-term borrowings less cash and cash equivalents.
7 Effective 2008, Canexus non-controlling interests are included in Equity.
8 Includes in-country cash taxes in Yemen.

	2010	2009	2008	2007	2006
Production Before Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	104.9	98.0	99.7	81.2	16.9
Canada	7.5	14.6	16.2	17.1	20.0
Long Lake Bitumen	15.9	7.9	3.9	–	–
Syncrude	21.2	20.2	20.9	22.1	18.7
United States	9.9	10.5	9.3	16.4	17.0
Yemen	41.3	49.9	56.6	71.6	92.9
Other Countries	2.1	3.5	5.8	6.2	6.3
	202.8	204.6	212.4	214.6	171.8
Natural Gas (mmcf/d)					
United Kingdom	35	24	18	16	20
Canada	126	139	131	118	108
United States	99	65	78	101	111
	260	228	227	235	239
Total Production Before Royalties (mboe/d)	246	243	250	254	212
Production After Royalties					
Crude Oil and NGLs (mbbls/d)					
United Kingdom	104.8	98.0	99.7	81.2	16.9
Canada	5.8	11.4	12.3	13.4	15.8
Long Lake Bitumen	15.1	7.9	3.9	–	–
Syncrude	19.6	18.6	18.2	18.8	16.9
United States	9.0	9.5	8.1	14.5	15.0
Yemen	23.1	29.8	30.6	39.8	51.8
Other Countries	1.9	3.2	5.3	5.7	5.7
	179.3	178.4	178.1	173.4	122.1
Natural Gas (mmcf/d)					
United Kingdom	35	24	18	16	20
Canada	116	128	109	98	91
United States	94	57	66	86	94
	245	209	193	200	205
Total Production After Royalties (mboe/d)	220	213	210	207	156
Oil and Gas Cash Netback Before Royalties[1] ($/boe)					
Producing Assets					
United Kingdom	68.27	59.06	87.70	67.85	55.53
Canada	16.73	16.07	32.97	20.07	22.87
Long Lake	(26.67)	–	–	–	–
Syncrude	38.22	29.00	53.83	41.94	37.86
United States	33.78	28.80	56.42	42.28	40.42
Yemen	24.16	20.55	31.11	25.52	26.35
Other Countries	64.47	48.50	86.58	61.94	57.71
Company-Wide Oil and Gas	44.38	38.55	60.64	43.22	32.75

1 *Defined as average sales price less royalties and other, operating costs and Yemen in-country taxes. Calculation details can be found in the Statistical Supplement on our website*

2010 RESERVES CONTINUITY

We had a successful 2010 capital investment program. We invested $2.5 billion in our oil and gas activities and added 101 million boe of proved reserves. These additions replaced 114% of our production and the conventional reserves replacement ratio of 105% was our best in four years.

	North Sea		Yemen	Other Intl	United States		Canada Other		Canada Insitu Oil Sands	Canada Syncrude	Total
(mmboe)	Oil	Gas	Oil	Oil	Oil	Gas	Oil	Gas	Synthetic	Synthetic	Oil and Gas
Proved Reserves [1]											
December 2009	169	3	23	43	22	28	37	44	318	324	1,011
Extensions & Discoveries	35	5	–	1	–	–	–	16	3	8	68
Acquisitions	1	–	–	–	–	–	–	–	–	–	1
Divestments	–	–	–	–	–	–	(34)	(2)	–	–	(36)
Revisions	26	5	6	(1)	1	–	–	(2)	(3)	–	32
Net Additions	62	10	6	–	1	–	(34)	12	–	8	65
Production	(38)	(2)	(16)	(1)	(4)	(6)	(3)	(7)	(4)	(8)	(89)
December 2010	**193**	**11**	**13**	**42**	**19**	**22**	**–**	**49**	**314**	**324**	**987**
Probable Reserves [1]											
December 2009	159	10	4	45	7	17	27	14	888	46	1,217
Extensions & Discoveries	3	3	–	–	–	–	–	17	–	8	31
Acquisitions	4	–	–	–	–	–	–	–	–	–	4
Divestments	–	–	–	–	–	–	(27)	(2)	–	–	(29)
Revisions	(1)	2	1	(5)	1	(2)	–	(3)	(3)	–	(10)
Net Additions	6	5	1	(5)	1	(2)	(27)	12	(3)	8	(4)
Conversions	(57)	(5)	(3)	(1)	(1)	(2)	–	–	(3)	(8)	(80)
December 2010	**108**	**10**	**2**	**39**	**7**	**13**	**–**	**26**	**882**	**46**	**1,133**
Proved + Probable Reserves [1]											
December 2009	328	13	27	88	29	45	64	58	1,206	370	2,228
Extensions & Discoveries	38	8	–	1	–	–	–	33	3	16	99
Acquisitions	5	–	–	–	–	–	–	–	–	–	5
Divestments	–	–	–	–	–	–	(61)	(4)	–	–	(65)
Revisions	25	7	7	(6)	2	(2)	–	(5)	(6)	–	22
Net Additions	68	15	7	(5)	2	(2)	(61)	24	(3)	16	61
Conversions	(57)	(5)	(3)	(1)	(1)	(2)	–	–	(3)	(8)	(80)
Production	(38)	(2)	(16)	(1)	(4)	(6)	(3)	(7)	(4)	(8)	(89)
December 2010	**301**	**21**	**15**	**81**	**26**	**35**	**–**	**75**	**1,196**	**370**	**2,120**

1 *We internally evaluate all of our reserves and have at least 80% of our proved and probable reserves assessed by independent qualified consultants each year; 99% of which were assessed this year. Our reserves are also reviewed and approved by our Board of Directors. Reserves represent our working interest before royalties using SEC rules which are based on average 2010 prices held constant. Gas is converted to equivalent oil at a 6:1 ratio. For more information on our reserves, see our 2010 Annual Information Form at www.nexeninc.com or www.sedar.com.*

FORWARD-LOOKING STATEMENTS

Certain statements in this report constitute "forward-looking statements" (within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for our capital program; future debt levels; availability of committed credit facilities; possible commerciality of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our operations; the expected timing and associated production impact of facilities turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs, future cost recovery oil revenues from our Yemen operations; the expectation of negotiating of an extension to certain of our production sharing agreements; the expectation of our ability to comply with the new safety and environmental rules enacted in the US at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; future demand for chemicals products; estimates on a per share basis; future foreign currency exchange rates, future expenditures and future allowances relating to environmental matters and our ability to comply therewith; dates by which certain areas will be developed, come on stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements. Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

All of the forward-looking statements in this report are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deepwater activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deepwater activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deepwater activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents, counterparties, contractors, and joint venture parties; volatility in energy trading markets; foreign currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and other factors, many of which are beyond our control. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement. Readers should also refer to the section titled "Risk Factors in our 2010 Annual Information Form available at www.nexeninc.com or under our profile on SEDAR at www.sedar.com.

Cautionary Note to US Investors

In this report, we may refer to "recoverable reserves", "recoverable resources", "recoverable contingent resources" and "prospective resources" which are inherently more uncertain than proved reserves or probable reserves. These terms are not used in our filings with the SEC. Our reserves and related performance measures represent our working interest before royalties, unless otherwise indicated.

Cautionary Note to Canadian Investors

Nexen has received an exemption from the securities regulatory authorities in the various provinces of Canada from certain requirements of *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") that permits us to disclose reserves estimates and related disclosures that have been prepared in accordance with SEC requirements. As a result of this exemption, Nexen's disclosures may differ from other Canadian companies. The differences between SEC requirements and NI 51-101 may be material for certain properties.

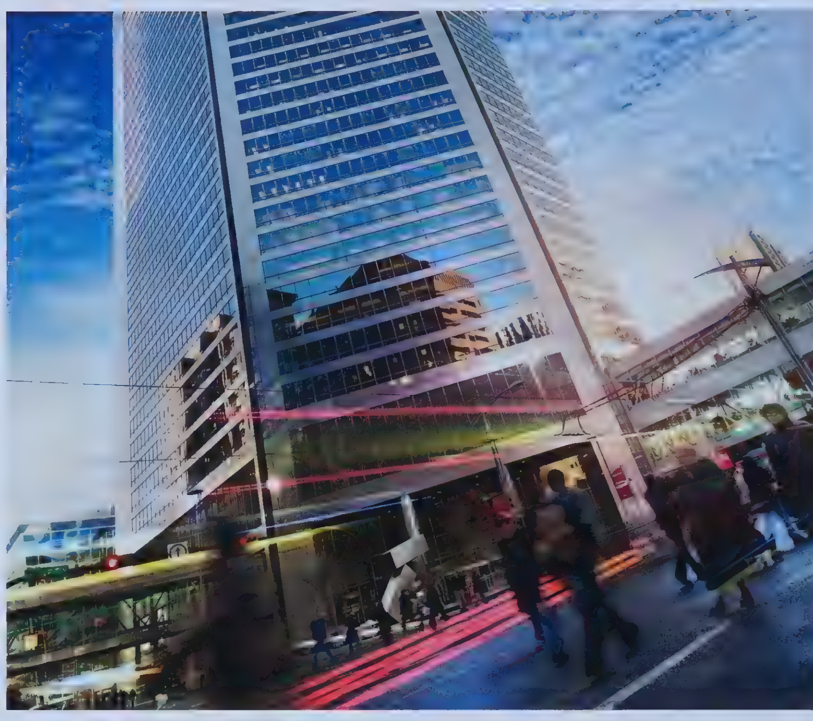
For more information on our reserves, our basis for reserves estimates and our exemption please refer to our 2010 Annual Information Form available at www.nexeninc.com or under our profile on SEDAR at www.sedar.com. Please also note:

• we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead; and

• because reserves data are based on judgments regarding future events actual results will vary and the variations may be material. Variations as a result of future events are expected to be consistent with the fact that reserves are categorized according to the probability of their recovery.

Cautionary statement: In the case of discovered resources or a subcategory of discovered resources other than reserves, there is no certainty that it will be commercially viable to produce any portion of the resources. In the case of undiscovered resources or a subcategory of undiscovered resources, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

CORPORATE INFORMATION



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Media and Ge[illegible]
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T: 403.699.5202

EARNINGS RELEASE DATES

Q1 – April 27, 2011
Q2 – July 14, 2011
Q3 – October 26, 2011
Q4 – February 16, 2012

OFFICERS

Francis M. Saville [illegible]
Chair of the Board

Marvin [illegible]
President and Chief Executive Officer

Kevin J. Reinhart
Executive Vice President
and Chief Financial Officer

Mathew [illegible]
Executive Vice President, International

Gary H. [illegible]
Executive Vice President, Canada

James T. Arn[illegible]
Senior Vice President,
Synthetic Crude

Eric B. [illegible]
Senior Vice President,
General Counsel and Secretary

Una M. Power
Senior Vice President,
Corporate Planning and
Business Development

Brian C. Reinsborough
Senior Vice President,
United States Oil and Gas

Catherine J. Hughes
Vice President, Operational Services,
Technology and Human Resources

[illegible]
Vice President
and Chief Information Officer

[illegible]
Vice President,
Global Exploration

[illegible]
Treasurer

[illegible]
Controller

[illegible]
Assistant Secretary

[illegible]
Assistant Secretary

[illegible]

[illegible]
11:00 a.m. M.D.T.
Tuesday, April 27, 2011
The Fairmont Palliser Hotel
133 – 9th Avenue SW
Calgary, Alberta, Canada

[illegible]
TSX and NYSE

[illegible]
7.35% Subordinated Notes
TSX—NXY.PR.U
NYSE—NXYPRB

Common Share
Transfer Agent and Registrars
CIBC Mellon Trust Company
Calgary, Toronto, Montreal
and Vancouver, Canada
BNY Mellon Shareowner Services
Jersey City, New Jersey, US

Dividend Reinvestment Plan
The offering circular (and for US residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or at www.cibcmellon.com

Auditors
Deloitte & Touche LLP
Calgary, Alberta, Canada

Conversions
Natural gas is converted at 6 mcf per equivalent barrel of oil.

Dollar Amounts
In Canadian dollars unless otherwise stated.

Significant Operating Entities
Nexen Inc.
Nexen Petroleum U.K. Limited
Nexen Petroleum U.S.A. Inc.
Nexen Marketing
Nexen Exploration Norge AS
Nexen Petroleum Nigeria Limited
Canadian Nexen Petroleum Yemen

ANNUAL INFORMATION FORM

ANNUAL INFORMATION FORM

ANNUAL INFORMATION FORM (AIF)

Below is a list of terms specific to the oil and gas industry. They are used throughout this AIF.

/d	=	per day	boe	=	barrel of oil equivalent
bbl	=	barrel	mboe	=	thousand barrels of oil equivalent
mbbls	=	thousand barrels	mmboe	=	million barrels of oil equivalent
mmbbls	=	million barrels	mcf	=	thousand cubic feet
mmbtu	=	million British thermal units	mmcf	=	million cubic feet
km	=	kilometre	bcf	=	billion cubic feet
MW	=	megawatt	WTI	=	West Texas Intermediate
GWh	=	gigawatt hours	Brent	=	Dated Brent
GJ	=	Gigajoules	NGL	=	natural gas liquid
PSC™	=	Premium Synthetic Crude™	NYMEX	=	New York Mercantile Exchange

GENERAL INFORMATION

In this AIF, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting 6,000 cubic feet of gas to one barrel of oil (6 mcf/1 bbl). This conversion may be misleading, particularly if used in isolation, as the 6 mcf/1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

The noon-day Canadian to US dollar exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

(US$)	**December 31**	**Average**	**High**	**Low**
2006	0.8581	0.8818	0.9099	0.8528
2007	1.0120	0.9304	1.0905	0.8437
2008	0.8166	0.9381	1.0289	0.7711
2009	0.9555	0.8757	0.9716	0.7692
2010	1.0054	0.9709	1.0054	0.9278

On January 31, 2011, the noon-day exchange rate was US$0.9978 for Cdn$1.00.

FORWARD-LOOKING STATEMENTS

Certain statements in this AIF constitute "forward-looking statements" (within the meaning of the *United States Private Securities Litigation Reform Act of 1995*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to, or associated with, individual wells, regions or projects. Any statements as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for our capital program; future debt levels; availability of committed credit facilities; possible commerciality of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our facilities; the expected timing and associated production impact of facilities turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash

flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs; future cost recovery oil revenues from our Yemen operations; the expectation of negotiating of an extension to certain of our production sharing agreements; the expectation of our ability to comply with the new safety and environmental rules enacted in the US at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; estimates on a per share basis; future foreign currency exchange rates; future expenditures and future allowances relating to environmental matters and our ability to comply therewith; dates by which certain areas will be developed, come on-stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

All of the forward-looking statements in this AIF are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

Forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deep-water activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deep-water activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deep-water activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents, contractors, counterparties and joint–venture partners; volatility in energy trading markets; foreign currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and other factors, many of which are beyond our control. These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled "Risk Factors" in this AIF and "Quantitative Disclosures About Market Risk" in our

management's discussion and analysis. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Included herein is information that may be considered financial outlook and/or future-oriented financial information (FOFI). Its purpose is to indicate the potential results of our intentions and may not be appropriate for other purposes. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

PRESENTATION OF INFORMATION

In this Annual Information Form, references to "we", "our", "us", "Nexen" or the "Company" mean Nexen Inc., our subsidiaries and partnerships.

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format. The information contained in this AIF is dated December 31, 2010, unless otherwise indicated.

Explanatory Note on Filing Changes

Nexen is listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE). Commencing in 2011 with our 2010 year-end disclosures, our annual disclosures will be in accordance with Canadian requirements and filed with the Securities and Exchange Commission (SEC) on Form 40-F, through the Multi-Jurisdictional Disclosure System available to Canadian reporting issuers. In previous years, we voluntarily used the Form 10-K (and related forms) to report our annual disclosures. Although the differences are substantively minor, we believe that basing our quarterly and annual disclosures on Canadian standards will enhance comparability of our information with that of our Canadian peers who generally report on this basis.

Until 2010, we had been relying on an exemption by Canadian securities regulators which allowed us to prepare and disclose reserves and related information in accordance with SEC requirements rather than National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). Under a new exemption, granted in December 2010, we are now permitted to prepare and disclose reserves and related information in accordance with SEC requirements in addition to NI 51-101 requirements. We have chosen to continue to report our reserves and related information in accordance with SEC requirements in our AIF, management's discussion and analysis (MD&A) and Consolidated Financial Statements. Reserves and related information prepared in accordance with NI 51-101 is separately filed on the system for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com under our profile. Canadian investors should read the "Special Note to Canadian Investors" on page 34.

Non-GAAP Measures

Certain financial measures referred to in this AIF, namely "cash flow from operations" and "net debt" do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and are therefore unlikely to be comparable to similar measures presented by others. These non-GAAP measures are included to assist investors in analyzing Nexen's operating performance, leverage and liquidity. Reconciliations of these non-GAAP measures to their nearest GAAP equivalent are presented in our MD&A.

Accounting Matters

In February 2008, the Canadian Institute of Chartered Accountants announced that publicly accountable enterprises must adopt International Financial Reporting Standards (IFRS) by January 1, 2011. For information regarding our adoption of IFRS, refer to the "New Accounting Pronouncements" section of our MD&A.

CORPORATE STRUCTURE

Nexen Inc. is incorporated under the Canada Business Corporations Act. Our registered and head office is located at 801–7th Avenue S.W., Calgary, Alberta, Canada T2P 3P7.

Our material operating subsidiaries owned directly or indirectly, their jurisdictions of incorporation and the percentage of securities beneficially owned, controlled or directed by us as at December 31, 2010 are as follows:

Name of Subsidiary	Jurisdiction of Incorporation/ Formation/Continuation	Percentage of Securities Owned, Controlled or Directed
Nexen Petroleum U.K. Limited	England & Wales	100%
Nexen Petroleum Nigeria Limited	Nigeria	100%
Nexen Petroleum Offshore USA Inc.	Delaware	100%
Nexen Marketing	Alberta	100%
Canadian Nexen Petroleum Yemen	Yemen	100%
Nexen Oil Sands Partnership	Alberta	100%

BUSINESS OVERVIEW

Nexen Inc. is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 as Canadian Occidental Petroleum Ltd. when Occidental Petroleum Corporation combined their Canadian crude oil, natural gas, sulphur and chemical operations into one company.

STRATEGY

Choice—it's what companies and investors value. Whether it's how we allocate capital, fund our growth, or invest in projects that make the most sense over the long term, choice is key. Our strategy is to build a sustainable energy company focused on delivering on execution and exploiting our existing three key growth areas: i) conventional exploration and development; ii) oil sands; and iii) unconventional gas.

Conventional Exploration and Development

Our conventional exploration and development assets are comprised of large acreage positions in select basins including the North Sea, deep-water Gulf of Mexico and offshore West Africa. Strategically, we focus on these basins due to: i) past successes; ii) existing infrastructure in place; iii) significant potential in remaining resource; and iv) attractive fiscal terms. Our global exploration team prioritizes investments in prospects that we expect will generate the highest value in our selected basins of choice.

In the North Sea, we are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. In addition to other producing properties, we operate the Buzzard field and platform, which is the largest discovery in the UK North Sea in over a decade. We have since made several other discoveries including the Golden Eagle area, Blackbird and Rochelle. We are actively exploring the basin including relatively under-explored areas such as west of the Shetland Islands and offshore Norway.

In the deep-water Gulf of Mexico, we made several significant discoveries including Gunnison, Aspen, Knotty Head, Wrigley and Longhorn. More recently, we made significant discoveries at Appomattox and Vicksburg. We are a large leaseholder in the Gulf. The deep-water Gulf is near infrastructure and continental US markets.

We have several significant discoveries offshore West Africa, including Usan, Usan West and Ukot, as well as at Owowo, offshore Nigeria. Development of the Usan field is progressing with construction of a floating production and storage offloading (FPSO) vessel and subsea facilities for expected first production in 2012.

Oil Sands

Our oil sands investments include interests in the Long Lake project, the Syncrude joint venture and 675,000 undeveloped acres (gross) in the Athabasca oil sands in northern Alberta. Our oil sands strategy is to generate steady and predictable cash flow for decades. While the cost to produce from the Athabasca oil sands is higher relative to conventional oil deposits, the significant discovered resource base and stable fiscal jurisdiction make this a key source of future oil development.

We first entered the oil sands by acquiring an interest in the Syncrude joint venture. Syncrude develops and produces synthetic crude oil from mining bitumen-saturated sands.

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop, produce and upgrade bitumen on joint lands in the Athabasca oil sands. Production here utilizes our patented OrCrude™ technology, which we expect will ultimately result in a significant margin advantage over conventional oil sands extraction and upgrading. Construction of the Long Lake project was completed in 2008 and we began producing PSC™ oil in 2009. In early 2009, we acquired an additional 15% interest in the Long Lake project and joint venture lands from OPTI, increasing our ownership level to 65%. Following this acquisition, we are now responsible for operating both the steam-assisted-gravity-drainage (SAGD) bitumen extraction process and the upgrader for Phase 1 as well as for future phases.

Unconventional Gas

Our unconventional gas strategy is focused primarily on the Horn River Basin in northeast British Columbia. The Horn River Basin is a significant shale gas play with high resource density and strong well productivity. We have over 300,000 acres of shale gas lands in the Horn River, Cordova and Liard shale gas basins in northeast British Columbia, with a 100% working interest in each. We have a substantial land position in the Horn River Basin, with approximately 90,000 acres in the Dilly Creek area.

Shale gas balances our corporate portfolio, which consists predominantly of large-scale, capital-intensive and long cycle-time projects. It provides natural gas exposure and short cycle-time projects where we control the scale and pace of development.

Three–Year Look Back

2008
- Achieved record financial results, generating cash flow from operations of $4.2 billion and net income of $1.7 billion
- Received government approval for the Usan development, offshore West Africa
- Started bitumen operations at Long Lake
- Acquired a significant land position in the Horn River shale gas play

2009
- Generated cash flow from operations of $2.2 billion and net income of $536 million
- Discovered the Hobby field in the UK North Sea, the first discovery of our Golden Eagle area
- Acquired an additional 15% working interest in the Long Lake project and completed first major turnaround to address steam reliability issues
- Produced first PSC™ from Long Lake
- Issued $1 billion of 10-year and 30-year senior notes
- Discovered Owowo field, offshore West Africa

2010
- Generated strong cash flow from operations of $2.1 billion and net income of $1.2 billion
- Discovered the Appomattox field in the deep-water Gulf of Mexico
- Disposed of non-core, heavy oil properties in Western Canada for $939 million
- Divested of non–core marketing businesses including North American natural gas marketing
- Doubled bitumen production at Long Lake with improved steam reliability
- More than doubled our British Columbia shale gas acreage, adding lands in the Cordova and Liard basins

In early 2011, we disposed of our investment in Canexus for net proceeds of $458 million.

During the remainder of 2011, we expect the following changes to our businesses:

- UK North Sea—sanctioning development of our discoveries in the Golden Eagle area, Blackbird and Rochelle, as well as continuing to explore the North Sea.
- US Gulf of Mexico—resuming exploration activity once drilling permits are received.
- Offshore West Africa—advancing construction and commissioning of the Usan project and exploring additional offshore acreage.
- Yemen—negotiating a potential five–year extension of the Masila block production sharing agreement.
- Long Lake—continuing to ramp-up bitumen production at Long Lake and assessing development plans of future oil sands phases.
- Shale Gas—bringing a nine-well pad on stream and initiating construction of an 18-well pad.

POSITIONED FOR SUCCESS—FOCUSED ON VALUE

Our goal is to grow long-term value for our shareholders responsibly. Key drivers to grow value are increasing reserves, production, cash flow and net income on a cost-effective basis over the long term. Success in our three strategic growth areas and existing producing properties delivers this growth. Today, we are building sustainable businesses in the North Sea, Western Canada, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:

RESOURCE INVENTORY

- Diversification—our assets are geographically diverse and we produce oil and gas, onshore and offshore. We have large conventional and unconventional legacy assets in our portfolio, which allows us to pursue value opportunities in varying economic environments.
- Significant captured resource—we have key resource plays with a low cost of entry. Our Long Lake project is developing only 10% of our oil sands leases in the Athabasca oil sands; we are an early player in the Horn River Basin shale gas play in northeast British Columbia; and we hold significant unexplored acreage in the Gulf of Mexico, the North Sea and offshore West Africa.
- Production weighted to crude oil—current production is approximately 85% and proved reserves are approximately 92% weighted to crude oil, respectively. The majority of our crude oil production is priced relative to international benchmarks such as Brent.

STRUCTURAL GROWTH

- Focus on growth—significant production growth is expected to come from identified projects currently under development. We are successful explorers with undeveloped discoveries at Knotty Head and Appomattox in the Gulf of Mexico, the Golden Eagle area in the UK North Sea, and Usan and Owowo, offshore Nigeria. We are ramping up production at Long Lake and continue to advance our shale gas play in the Horn River Basin. We expect to add about 70,000 boe/d of new production over the next 24 months as we bring on Usan, UK tiebacks, shale gas and ramp up at Long Lake. We expect further upside from a successful Yemen contract extension and development of our existing discoveries.

FINANCIAL STRENGTH

- Strong financial position—we have access to approximately $4 billion of liquidity through cash and undrawn committed credit facilities that allow us to proceed with investments at our pace and to take advantage of opportunities as they arise.
- Industry-leading cash netbacks—position us well to withstand lower commodity prices.

SUPERIOR TALENT

- International expertise—we are an international operator with a proven track record of successful business ventures in Yemen, Canada, the United States, the United Kingdom, Nigeria and Colombia.
- Employer of choice—proven ability to attract and retain talent (Top 100 Employer for 2011 in the annual Media Corp ranking survey).
- Skilled workforce—we significantly enhanced our technical skills over the last few years by hiring highly experienced employees for our oil sands, shale gas and Gulf of Mexico businesses.

HOW WE DO BUSINESS

- Sustainable business practices—leveraging our strength in business practices such as health, safety, environment and social responsibility (HSE&SR) to access opportunities and responsibly create and demonstrate both long-term benefits and value growth for our investors, for the communities in which we operate and for other stakeholders. This makes us a desired business partner and/or joint venture operator and welcome in the communities in which we operate.
- Leadership—industry leader in governance, community relations and environmental stewardship. We received several external recognition and awards for our governance practices and disclosures.

OIL AND GAS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, western Canada, Yemen, offshore West Africa, Colombia, and Norway. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

In this AIF, we provide estimates of remaining quantities of proved and probable oil, synthetic oil and natural gas reserves (oil and gas reserves) for our various properties as at December 31, 2010. These reserves estimates and related disclosures have been prepared in accordance with the definitions and disclosure requirements prescribed by the SEC. We have also prepared reserves estimates in accordance with NI 51-101. Our Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1 has been filed at the same time as this AIF on SEDAR at www.sedar.com. Reserve estimates and disclosures prepared in accordance with SEC requirements differ from reserves estimates prepared in accordance with NI 51-101. Significant qualitative differences between SEC and NI 51-101 reserves estimates and disclosures are described in the section entitled "Special Note to Canadian Investors" on page 34.

Our proved and probable reserve estimates have been internally prepared. For our reserves estimates prepared in accordance with SEC requirements, we had 99% of our proved reserves before royalties (99% after royalties) assessed (either evaluated or audited as described on pages 31 to 34) by independent reserves consultants. Their assessment of the proved reserves are performed at varying levels of property aggregation, and we work with them to reconcile any difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10% either positively or negatively, however, we believe such differences are not material relative to our total proved reserves.

We also had 99% of our proved plus probable oil and gas reserves before royalties (99% after royalties) assessed by independent reserves consultants. By definition, probable reserves must be determined together with proved reserves (see definition on page 30). As such, the independent reserves consultants' assessments are prepared on a combined proved plus probable basis. Like proved reserves, their assessment of the proved plus probable reserves are performed at varying levels of property aggregation, and we work with them to reconcile any difference on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10% either positively or negatively, however, we believe such differences are not material relative to our total proved plus probable reserves.

Refer to the section on Basis of Reserves Estimates on pages 31 to 34 for a description of our internal reserves process and the nature and scope of the independent assessments performed on our proved and probable reserves estimates and the results thereof.

UNDERSTANDING THE OIL AND GAS INDUSTRY

The oil and gas industry is highly competitive. With strong global demand for energy and limited exploration opportunities, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price that products attract based on quality, location and marketing efforts. We have captured an inventory of significant opportunities in our core growth areas, and our goal is to extract the maximum value from each barrel of oil equivalent so that every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash flow generated from operations. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices, and we maintain liquidity that provides us with the ability to sustain capital investment in high-quality projects during periods of low commodity prices.

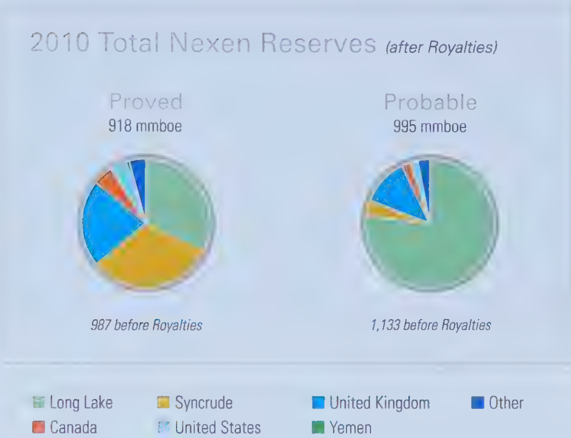
The prices we receive for our oil and gas products are determined by global crude oil and natural gas markets and regional dynamics, all of which can be volatile. With many alternative customers, the loss of any one customer is not expected to have a significantly adverse effect on the price of our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products such as natural gas can fluctuate season to season, which impacts price. We manage our operations on a country-by-country basis, reflecting differences in the regulatory regime and competitive environments and risk factors associated with each country.

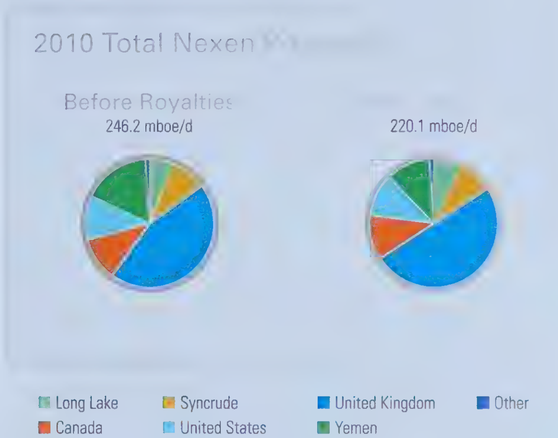
Our oil and gas operations are broken down geographically into the UK North Sea, Canada, Syncrude, US Gulf of Mexico, Yemen and Other International (currently Colombia, offshore West Africa and Norway). Results from our Long Lake project and shale gas are included in Canada. We also report on our energy marketing operations.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 23 to the Consolidated Financial Statements and in our MD&A. Reserves and related information for our oil and gas operations are prepared in accordance with SEC disclosure standards in this AIF. Reserves prepared in accordance with Canadian disclosure standards as set out in NI 51-101 are available on Form 51-101F1, filed in Canada on SEDAR at www.sedar.com.

NEXEN CONSOLIDATED RESERVES AND PRODUCTION

In the charts below, our consolidated proved and probable reserves as at December 31, 2010 are presented, along with our oil and gas production for the year ended December 31, 2010. Further information on our reserves related information is found on page 25 of this AIF.

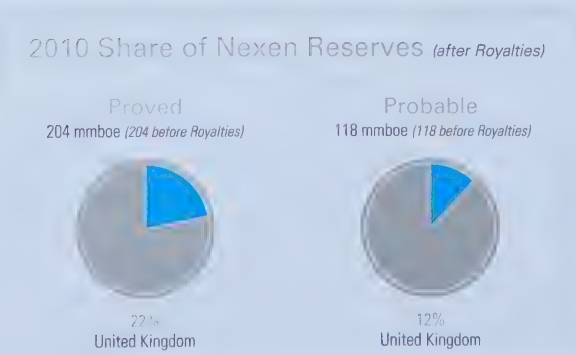


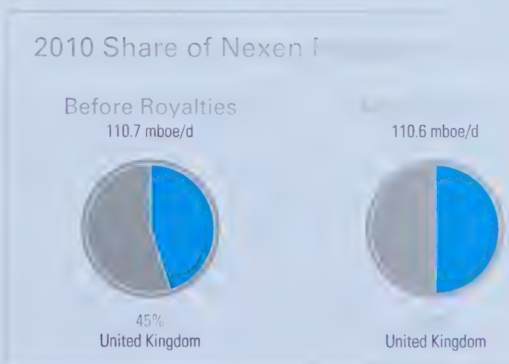


CONVENTIONAL EXPLORATION AND DEVELOPMENT

United Kingdom (UK)

- We are the second largest oil producer in the UK North Sea.
- We are progressing our significant discovery in the Golden Eagle area, with development sanctioning targeted in 2011.
- We continue to actively explore the North Sea, with six exploration and appraisal wells planned for 2011.





The UK North Sea is a key producing area for Nexen. Our primary assets, which we operate, include a 43.2% interest in the Buzzard field and facilities, a 41.9% interest in the Scott field and production platform, an 80.4% interest in the Telford field and a 79.7% interest in the Ettrick field, along with interests in several undeveloped discoveries and more than 954,000 net undeveloped exploration acres. We are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. Our UK North Sea operations complement our global portfolio with significant cash flow generation and the opportunity for short cycle-time production growth.

Our UK strategy is to grow our existing North Sea production and identify new production sources. To do this, we identify exploration and exploitation opportunities near existing infrastructure that can be tied-in economically in a short time period.

BUZZARD

Buzzard is the largest discovery in the UK North Sea in over a decade. It was discovered in 2001 and came on stream in early 2007.

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. The Buzzard development was initially comprised of three platforms capable of processing at least 200,000 bbls/d of oil and 60 mmcf/d of gas. In late 2010, a fourth platform with production-sweetening facilities to handle higher levels of hydrogen sulphide was brought on line. Oil from Buzzard is exported via the Forties pipeline to the Kinneil Terminal in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

We expect to produce the Buzzard field through 36 production wells and maintain reservoir pressure with an active water-flood program. We have drilled 26 of these wells to date and 16 of these wells are now available for production. A further six wells will be available for production in early 2011 due to the additional production-sweetening facilities. Our share of production in 2010 was 80,500 boe/d. We expect to drill four additional development wells in 2011.

SCOTT/TELFORD

Scott and Telford are producing fields with additional exploitation opportunities. Scott was discovered in 1987 and began producing in September 1993, while Telford was discovered in 1991, tied back to the Scott platform and came on stream in 1996. Most of our oil and gas from the fields is produced through subsea wells tied back to the Scott platform. Oil is delivered to the third-party Kinneil Terminal in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in northeast Scotland. In recent years, the Scott platform has undergone several significant maintenance turnarounds and facilities upgrades to improve reliability and extend facility life. Recently, successful extension drilling of the Telford field exceeded our expectations and extended the field's proved reserves. Late in 2010, we acquired an additional 8.7% interest in the Telford field. The nearby Rochelle discovery is planned to be tied back to the Scott platform by early 2012. Scott/Telford produced 13,900 boe/d (net to us) in 2010.

ETTRICK

Ettrick is a producing field, originally discovered in 1981 and brought on stream in 2009. Oil and gas is produced from the fields through subsea wells tied back to an FPSO. During 2010, production from the field was ramped up to full rates. The FPSO is designed to handle 30,000 bbls/d of oil and 35 mmcf/d of gas and to re-inject 55,000 bbls/d of water. Production from the nearby Blackbird field is planned to be tied back to the Ettrick FPSO in 2012. Our 2010 share of production was 14,500 boe/d.

OTHER

We have interests in two smaller non-operated fields in the UK North Sea. The Farragon field was brought on stream in late 2005. In 2007, the Duart field began producing oil from a single well tied back to a third-party platform.

EXPLORATION AND UNDEVELOPED ASSETS

We continue to actively explore in the UK North Sea and hold several undeveloped discoveries on operated blocks near Scott, Buzzard and Ettrick as follows:

Field	Interest *(%)*	Operator Status	Comments
Blackbird	80	operated	discovery near Ettrick; tie back to Ettrick FPSO by 2012
Polecat	40	operated	discovery near Buzzard; evaluating development alternatives
Golden Eagle	37	operated	discovery near Buzzard; development sanctioning in 2011
Hobby	37	operated	discovery near Golden Eagle; development sanctioning in 2011
Pink	37	operated	discovery near Golden Eagle; development sanctioning in 2011
Kildare	50	operated	discovery near Scott; evaluating development alternatives
Rochelle	44	non-operated	discovery near Scott; tie back to Scott platform by 2012
West Rochelle	TBD	non-operated	discovery near Scott, evaluating development alternatives

In 2007, we discovered hydrocarbons at Golden Eagle, followed by Pink in 2008, and early in 2009 we made a discovery at Hobby. We refer to these three discoveries as the Golden Eagle area. During 2009, we successfully completed a comprehensive appraisal program of these discoveries, which included drilling nine appraisal wells, two drill-stem tests and one injection test. In 2010, we expanded our acreage in this area and progressed development plans of the discoveries. In 2011, we plan to complete appraisal work, explore additional acreage and sanction the development plan. With the success achieved to date, we expect the Golden Eagle area will become a significant asset over the next few years.

In the UK North Sea, we plan to drill a total of four exploration wells and two appraisal wells in 2011.

FISCAL TERMS

In the UK, new discoveries pay no royalties and result in cash netbacks that are higher than our company average. The Scott field is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which is expected to occur in 2011. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance for the field. PRT is applicable to fields receiving development consent prior to March 1993. Our other fields in the UK North Sea are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate on oil and gas activities is 30% of taxable income, and oil and gas activity is subject to a 20% supplemental charge.

United States (US) — Gulf of Mexico

- We are a significant leaseholder in the deep-water Gulf of Mexico, a world-class basin with excellent potential.
- We are appraising our Appomattox discovery in the emerging Norphlet play.
- We are advancing our Knotty Head discovery towards project sanction.

The Gulf of Mexico is an integral part of our growth strategy. Existing production infrastructure, the potential for material discoveries, and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. While costs of deep-water exploration are typically higher, prospects generally have multiple sands and higher production rates—factors that enhance economics. The technology to find, drill and develop discoveries is rapidly progressing. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time frames relative to less developed or more remote areas of the world. We focus our exploration program on Miocene sub-salt plays and Norphlet targets in the Central Gulf of Mexico.

Over the past few years, we have built our resources and capabilities to explore in the deep water by accumulating a large inventory of acreage to high-grade prospects, hired new employees with significant Gulf of Mexico oil and gas experience and gained access to two new-build deep-water drilling rigs. These activities have yielded major discoveries in both plays and a high quality prospect portfolio to fuel further exploration.

Our current Gulf production and reserves are primarily concentrated in five deep–water and five shallow–water (shelf) areas.

DEEP WATER

Most of our deep-water production comes from our 25% non-operated Longhorn field, our 50% non-operated Wrigley field, our 100% operated Aspen field, and our 30% non-operated Gunnison field. Our share of 2010 deep-water production before royalties was 18,200 boe/d (16,400 after royalties).

Our Longhorn property is on Mississippi Canyon Blocks 502 and 546 in 2,400 feet of water. The project is a non-operated four-well subsea tie-back to the Corral platform located 19 miles north of the field. Longhorn came on stream in late 2009 and achieved production of approximately 200 mmcf/d gross (50 net to us) in 2010.

Wrigley is on Mississippi Canyon Block 506 in 3,300 feet of water. The project began gas production in 2007 and consists of a single subsea well tied back to the Shell-operated Cognac platform 17 miles away.

Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the third-party operated Bullwinkle platform 16 miles away and began producing in late 2002.

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in late 2003 through a truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas. We achieved payout on Gunnison in December 2005, just two years after first production.

In 2007, we acquired three deep-water fields: i) Garden Banks Block 205; ii) Green Canyon 137; and iii) Green Canyon 6/50. These fields are in water depths between 700 and 1,100 feet. Production from Green Canyon 6/50/137 has been suspended as the third-party platform that processed our oil and gas was destroyed by Hurricane Ike in September 2008. During 2010, the lease on Green Canyon 137 expired. We are assessing our options to restore field production from Green Canyon 6/50, which may include building our own processing platform, a tie-back to a third-party platform or potentially divesting the asset.

SHELF

Our shelf producing assets are offshore Louisiana, primarily in four 100%-owned field areas: Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 76 (consisting of Blocks 65, 66 and 67) and West Delta. Given the mature nature of these assets and our focus on deep-water exploration, our 2011 capital investment on these assets is expected to be minimal.

EXPLORATION AND UNDEVELOPED ASSETS

We hold approximately 207 blocks in the Gulf of Mexico and expect this acreage and future exploration opportunities to position us well for continued growth. Our undeveloped deep-water discoveries include:

Well	Interest *(%)*	Operator Status	Comments
Appomattox	20	non-operated	discovery; further appraisal required
Knotty Head	25	non-operated	discovery; currently evaluating development options
Vicksburg	25	non-operated	discovery; further appraisal required

In 2010, we completed a successful exploration well and sidetrack at Appomattox, approximately six miles west of our Vicksburg discovery. Results of these activities indicated a significant oil discovery. Additional appraisal wells are planned to further delineate this discovery throughout 2011 once the US regulatory agencies issue necessary drilling permits. Elsewhere in 2010, we completed drilling a second appraisal well at Knotty Head and signed a letter of intent to jointly develop our discovery with the third-party Pony discovery on the offsetting block to the north. We plan to have an integrated project team in place in early 2011 to work on a joint development plan for both blocks.

In 2011, we plan to drill up to three exploration wells in the deep-water Gulf of Mexico, focusing on the Miocene sub-salt play.

The BP Macondo oil spill and the subsequent drilling moratorium did not impact our production in 2010, however, our exploration drilling programs are delayed as US regulatory agencies have not yet issued new Gulf of Mexico drilling permits. Subsequent to the drilling moratorium, new rules have been enacted in the US regarding improving the safety of offshore operations, safeguarding the environment, strengthening oil spill response, planning and capacity, advancing well containment capabilities, deep-water drilling procedures, wellbore integrity and blowout prevention. We expect to be able to comply with the new rules at a minimal incremental cost. We expect that drilling permits will be granted at a slower pace in the future than before the moratorium. We believe our drilling practices comply with the new regulatory requirements and expect to resume exploration drilling in 2011 once appropriate drilling permits are received.

FISCAL TERMS

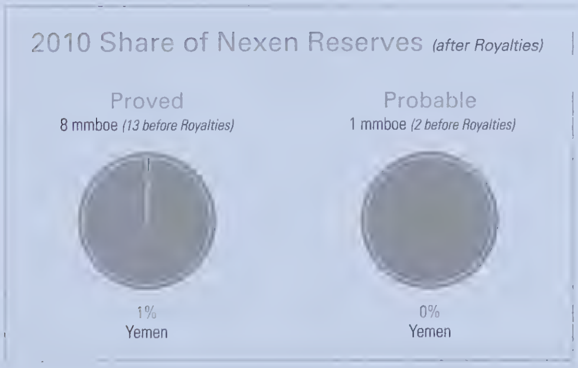
In 2010, royalty rates on our US production averaged 17% for shelf volumes and 3% for deep-water volumes. The US government increased royalty rates from 12.5 to 18% for new deep-water leases awarded after July 2007. Our Aspen and Gunnison fields are not subject to royalties on the first 87.5 mmboe of production. Our Wrigley and Longhorn fields are not subject to royalties on the first 9 mmboe of production if realized prices do not exceed certain price thresholds as determined by the regulators. Natural gas prices did not exceed the threshold in 2010 and, therefore, no royalties were due on these properties. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0 to 12%.

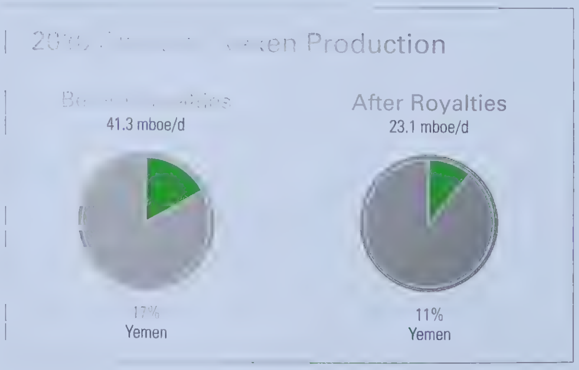
Other International

- Our entry into Yemen kicked off our international expansion in the early 1990s, which provided us with other significant international opportunities.
- Development of the Usan field, offshore Nigeria is currently under construction. We have several discoveries and additional exploration prospects beyond Usan.
- We are leveraging international exploration and operating success with experience to pursue unconventional resources abroad.

YEMEN

Yemen has been a significant international region for us since we first began production at Masila in 1993. We operate the country's largest oil project and have developed strong relationships with the government and local communities. Our strategy in Yemen is to maximize the value from our two existing producing blocks: Masila (Block 14) and East Al Hajr (Block 51). We are also reviewing our opportunities in Yemen for potential future exploration activities.





Masila Block (Block 14)

We operate the Masila project with a 52% working interest. The Masila fields are mature but still hold significant value, generating cash flow in excess of capital requirements. Under the Masila Production Sharing Agreement (PSA) between the Government of Yemen and the Masila joint venture partners (Masila Partners), we have the right to produce oil from Masila to December 17, 2011. We are currently negotiating a five-year extension of the Masila PSA with the Yemen Government. There is no assurance that this extension will be received.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993. Masila crude oil averages 32° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations, including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations. Production is collected at our central processing facility (CPF), where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal on the Indian Ocean and shipped to customers, primarily in Asia.

Production is divided into cost-recovery oil and profit oil. Cost-recovery oil provides for the recovery of all exploration, development and operating costs that are funded by the Masila Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for four years
Development	16.7% per year for six years

The remaining production is profit oil that is shared between the Masila Partners and the government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20 to 33%. The structure of the agreement moderates the impact on the Masila Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the government. The government's share of profit oil includes a component for Yemen income taxes paid by the Masila Partners at a rate of 35%. In 2010, the Masila Partners' share of production, including recovery of costs, was approximately 43%.

East Al Hajr Block (Block 51)

The first successful exploratory well was drilled in 2003 and development of the block began in 2004, which included a CPF, gathering system and a 22 km tie-back to our Masila export pipeline. Production commenced in November 2004.

We operate Block 51, which is governed by the Block 51 PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners): The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures and, therefore, our effective interest is 100% and, for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. We recognize both the government's share and TYCO's share of profit oil under the Block 51 PSA as royalties and taxes. The PSA expires in 2023 and we have the right to negotiate a five year extension. Under the Block 51 PSA, the EAH Partners pay a royalty ranging from 3 to 10% to the government depending on production volumes. The remaining production is divided into cost-recovery oil and profit oil. Cost-recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen.

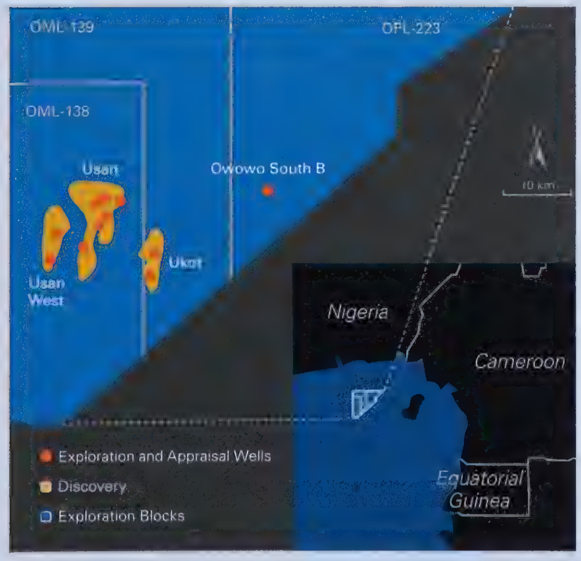
Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% in year one, 25% in year two
Development	75% in year one, 25% in year two

The remaining production is profit oil that is shared between the EAH Partners and the government on a sliding scale based on production rates. The EAH Partners' share of profit oil ranges from 20 to 30%. The government's share of profit oil includes a component for Yemen income taxes paid by the EAH Partners at a rate of 35%. In 2010, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 44%.

NIGERIA

Offshore West Africa is a core area where we have several discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to complete development of the Usan discovery and continue to explore our portfolio to provide medium to long-term growth.



In 1998, we acquired a 20% non-operated interest in Block OPL–222, which covers 448,000 acres approximately 80 km offshore in water depths ranging from 600 to 3,500 feet. In 1998, we discovered the Ukot field and encountered three oil-bearing intervals. This was followed up by a successful appraisal well in 2003. In 2002, the Usan field was discovered and seven more successful wells confirmed that significant hydrocarbons exist on the block.

Development of the Usan field is progressing well and is expected to come on stream in 2012, ramping up to peak production rates of 180,000 bbls/d (36,000 bbls/d, net to us). Construction of the FPSO hull and subsea facilities continued in 2010 and the major topside modules were successfully installed onto the FPSO deck. The FPSO is now over 90% complete and will be capable of storing up to two million barrels of oil. We expect that our total investment in the Usan development will be approximately $2 billion (net to us).

In 2008, we acquired an 18% non-operated interest in Block OPL–223, covering 230,000 acres, which provides us with future exploration potential on the adjacent block. In 2009, we completed drilling an exploration well in the southern portion of Block OPL–223. The Owowo South B-1 well was drilled in a water depth of 670 metres and is located 20 km northeast of the Usan field. Under the Production Sharing Contract governing OPL–223, the Nigerian National Petroleum Corporation is the concessionaire of the licence, which is operated by Total Exploration & Production Nigeria Ltd. We continue to explore offshore West Africa for potential prospects.

As is typical in many jurisdictions, the Nigerian government is reviewing its existing petroleum fiscal terms, including those applicable to our interests, the impact of which could negatively affect the economics of our project.

COLOMBIA

In 2000, we made a discovery at Guando on our 20% non-operated Boqueron Block, and production from Guando began in 2001. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 100 km southwest of Bogota. Under terms of our licence, our working interest in Guando decreased from 20 to 10% during the second quarter of 2009, as cumulative oil production from the field reached 60 million barrels.

Production from Guando is subject to a royalty between 5 and 25% depending on daily production. In 2010, the royalty payable to the Colombian government averaged 8%. Colombian taxable income is subject to federal income tax of 33%.

We currently hold interests in one development block, three exploration and production blocks and two technical evaluation agreements in the Upper Magdalena Basin and the Eastern Cordillera area. In the Upper Magdalena Basin, we hold a 10% interest in the Boqueron block and a 50% non-operating interest in the Villarrica Norte Block. In the Eastern Cordillera area, we hold a 100% interest in the Chiquenquira and Sueva exploration and production blocks, and a 100% interest in the Fomeque and Lower Villetta technical evaluation agreements.

NORWAY

Norway is a natural extension of our conventional offshore growth strategy in the North Sea given our geological experience with the UK. The Norwegian continental shelf is characterized by well-developed infrastructure and potentially significant hydrocarbon resources. The Norwegian government incentivized the oil and gas industry to explore this area by providing a 78% cash tax refund on qualifying exploration expenditures to companies that are not taxable.

We hold working interests in nine exploration licences in the Norwegian North Sea. In 2010, we acquired additional seismic and drilled an unsuccessful exploration well. In 2011, we expect to drill at least one exploration well and continue to add to our portfolio through participation in annual licensing rounds and farm-ins. Norwegian oil and gas income is subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax.

OIL SANDS

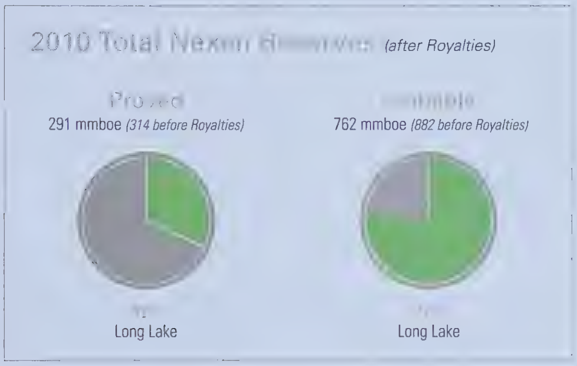
- Long Lake production and upgrading capacity continued to ramp up during the year.
- We have significant undeveloped acreage in the Athabasca oil sands, totaling over 675,000 acres (gross).
- Syncrude has been operating for over 30 years and provides steady predictable cash flows.

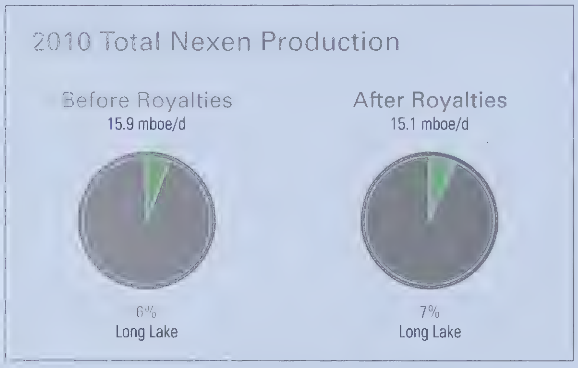
The Athabasca oil sands deposit in northeast Alberta is a key growth area for us. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth over the long–term. Our Long Lake project involves integrating SAGD bitumen production with field-upgrading technology to produce PSC™ for sale, and synthetic gas, which significantly reduces our need to purchase natural gas for operations. We also have a 7.23% investment in the Syncrude oil sands mining and upgrading operation as well as significant undeveloped acreage.

Insitu Oil Sands

In 2001, we formed a 50/50 joint venture with OPTI to develop the Long Lake lease using SAGD for bitumen production and proprietary OrCrude™ technology for the first stage of upgrading. OPTI has the exclusive Canadian licence for the OrCrude™ technology. We acquired the exclusive right to use this technology with OPTI within approximately 160 km of Long Lake, and the right to use the technology elsewhere in Canada and the rest of the world (excluding Israel) subject to certain rights of OPTI to participate.

SAGD bitumen operations started mid 2008 and we began producing PSC™ from the upgrader in 2009. Early in 2009, we acquired an additional 15% interest in the Long Lake project and the joint venture lands from OPTI, increasing our ownership level to 65%. Following this acquisition, we are now responsible for operating both the SAGD bitumen extraction process and the upgrader for Phase 1 and future phases.





SAGD AND UPGRADER INTEGRATION

The SAGD process involves drilling two parallel horizontal wells, with horizontal portions generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude oil is upgraded to light (39° API) PSC™, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel for generating steam and as a source of hydrogen for the hydrocracking process. The gas is also consumed in a cogeneration plant to produce electricity for on-site use and sale to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is about 90%, compared to 75% for a typical bitumen-fed coker based plant, which we expect will provide us with a significant margin advantage in the long term.

OUR STRATEGIC ADVANTAGE

Our integrated SAGD and upgrading process addresses three main economic hurdles of SAGD bitumen production: i) the potentially high cost of natural gas; ii) the cost and availability of diluent; and iii) the typically lower realized price of bitumen. Using synthetic gas from the asphaltenes as fuel, we expect to purchase considerably less natural gas. With the upgrading facilities on site, diluent is not required to transport the bitumen to market. By upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands the same premium price as light, sweet crude oil.

LONG LAKE PROJECT

The Long Lake project received regulatory approval in 2003 and was sanctioned in 2004. In 2007, we began injecting steam into the well pairs. We continued to steam the SAGD well pairs and began turning wells over to SAGD production in 2008. In 2009, we improved steam reliability and operability. We also installed electric submersible pumps (ESPs) in a number of our SAGD wells throughout 2009 and 2010. This allows us to improve pressure control in the wells and should ultimately reduce our overall steam-to-oil ratio (SOR). The first several months of steam injection in a well pair largely involve heating the reservoir, followed by a ramp-up of bitumen production to peak rates over 12 to 24 months. Our ramp-up has been slower than initially anticipated but still within industry experience. At the start of production, SORs are high but is expected to decline as bitumen production ramps up to our target rates. We expect the SOR to be in the range of three to four over the long term.

Our share of SAGD bitumen production in 2010 averaged 24,400 bbls/d (15,900 net to us). We are currently producing approximately 27,000 bbls/d of bitumen (17,600 net to us).

We completed construction of the upgrader in 2008 and began commissioning for commercial operations shortly thereafter. Initial production of PSC™ oil from the upgrader began in 2009. As the upgrader ramps up to capacity, we expect periods of downtime as we work through the various stages of commissioning and ramp-up. This periodic downtime is normal following initial facility start-up and consistent with industry experience, especially when dealing with new technologies. We are also progressing projects that will increase the operating independence between our SAGD facilities and the upgrader while maintaining the benefits of integration. During the bitumen ramp-up period, we have purchased third-party bitumen to assist with upgrader start-up. Production design capacity for Long Lake is approximately 60,000 bbls/d (39,000 net to us at a 65% working interest) of PSC™. We expect to maintain production over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

In 2010, we processed about 29,200 bbls/d gross of bitumen through the upgrader, producing 19,400 bbls/d gross of PSC™. Combined SAGD, cogeneration and upgrading operating costs are expected to average about $30/bbl once we reach design capacities, which are substantially lower than coking or other upgrading processes as a result of the reduced energy input costs. We expect ongoing capital costs to average between $5/bbl and $10/bbl depending on well spacing, well length and recovery factor. The full-cycle capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

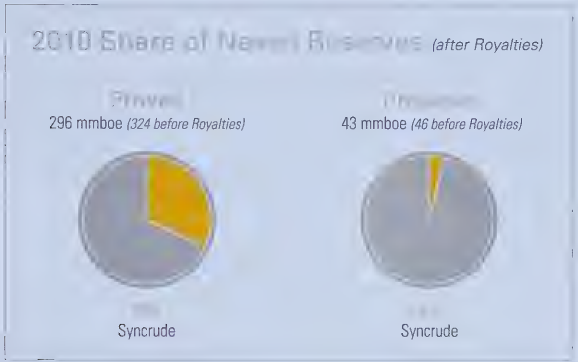
FUTURE PROJECTS

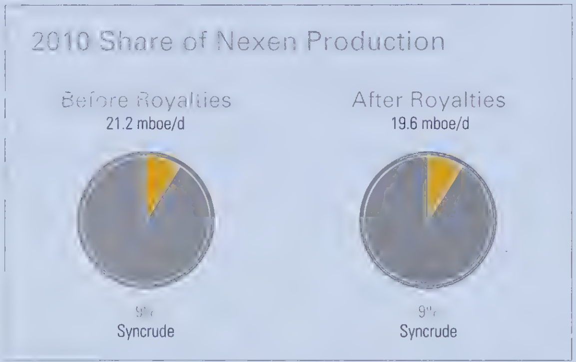
We have approximately 290,000 net acres of bitumen-prone lands in the Athabasca region. We plan to continue developing our bitumen lands in phases. In 2010, we invested $30 million on additional drilling, seismic and engineering to develop our leases and advance regulatory applications for future phases. Long Lake is expected to be followed by additional phases with each project leveraging knowledge and experience from previous phases. We currently have regulatory approval for up to 140,000 bbls/d at our second phase of Long Lake, called Kinosis.

Kinosis is expected to be similar in design but will have two smaller SAGD stages feeding the upgrader. The upgrader will be constructed after bitumen production from the first SAGD stage ramps up, provided economics of upgrading are favorable. By keeping the core team in place, and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

Syncrude

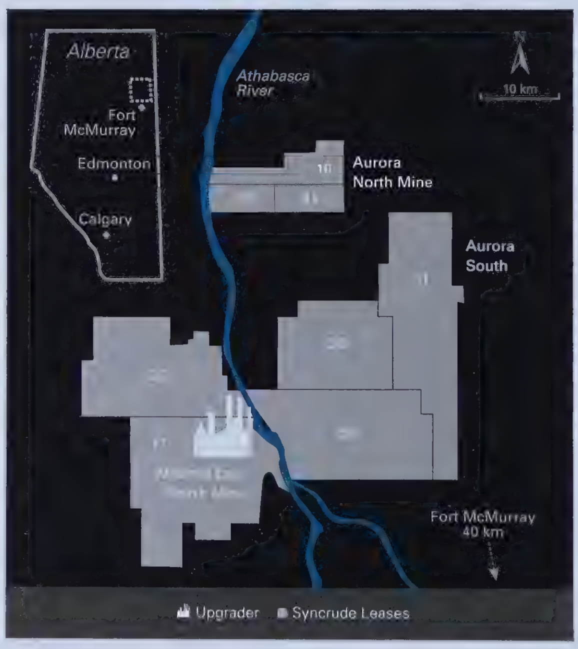
We hold a 7.23% participating interest in the Syncrude joint venture. This joint venture was established in 1975 to mine shallow oil sand deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil. Syncrude's operating strategy is to develop this resource, focusing on safe, reliable and profitable operations.





Syncrude exploits a portion of the Athabasca oil sands that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14% by weight and ore-bearing sand thickness of 100 to 160 feet. Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31 and 34) covering 248,300 acres, 40 km north of Fort McMurray in northeast Alberta. Syncrude currently mines oil sands at two mines: Mildred Lake North and Aurora North. These locations are readily accessible by public road. Trucks and shovels are used to collect the oil sands in the open-pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 310 million tons of oil sands per year and between 140 and 160 million barrels of bitumen per year depending on the average bitumen ore grade. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Mildred Lake North Mine uses hot water, steam and caustic soda to create a slurry, while at the Aurora North Mine, the oil sands are mixed with warm water. Close to 90% of the water used in operations is recycled from the upgrader and mine sites. Incremental water is drawn from the Athabasca River in accordance with existing licences.



The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading. The resulting products are then separated into naphtha, light gas-oil and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2010, about 45% of the synthetic crude oil was sold to refineries in Eastern Canada, 40% to those in the mid-western United States and the remaining 15% was sold to refineries in the Edmonton area. Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than two billion barrels of synthetic crude oil to Edmonton by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 and 2009 to accommodate increased Syncrude production.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating licence for the eight oil sands leases through to 2035. The licence permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start-up of operations in 1978.

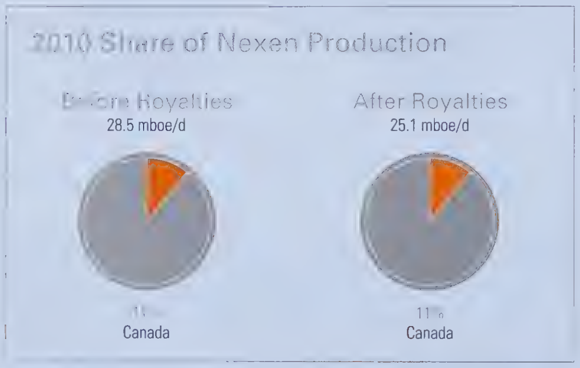
In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 40 km north of the main Syncrude site. The next expansion of Syncrude came on stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project.

Syncrude pays royalties to the Alberta government. As of January 2002, this royalty was equal to the greater of 1% of gross revenue or 25% of net synthetic-based profit after deducting bitumen related operating expenses and new capital expenditures. In connection with the provincial government's review of Alberta royalty rates in 2007, the Syncrude owners negotiated revised royalty terms at the request of the government. Effective January 1, 2009, and consistent with other oil sands producers, Syncrude began paying royalties based on bitumen, rather than paying royalties calculated on fully upgraded synthetic crude oil. As a part of this conversion, the Alberta government will recapture royalties related to upgrader capital expenses of about $5 billion (gross) that were deducted against prior royalties from future production. The $5 billion royalty deductions previously received by the Syncrude owners will be recaptured by the Alberta government over a 25-year period. In addition, the Province of Alberta and Syncrude reached an agreement to establish new transitional royalty terms. Under the terms of the agreement, until December 31, 2015, Syncrude will continue to pay base royalty rates (being the greater of 25% of net bitumen-based revenues, or 1% of gross bitumen-based revenues) plus an incremental royalty of up to $975 million (our share $70.5 million). The incremental royalty is subject to certain minimum bitumen production thresholds and is to be paid in six annual payments. This agreement is in lieu of the Syncrude owners converting to the Province of Alberta's new royalty framework announced in October 2007, that became effective January 1, 2009. After January 1, 2016, the rates under the new Alberta royalty framework will apply to the Syncrude project. See Fiscal Terms on page 24.

UNCONVENTIONAL GAS

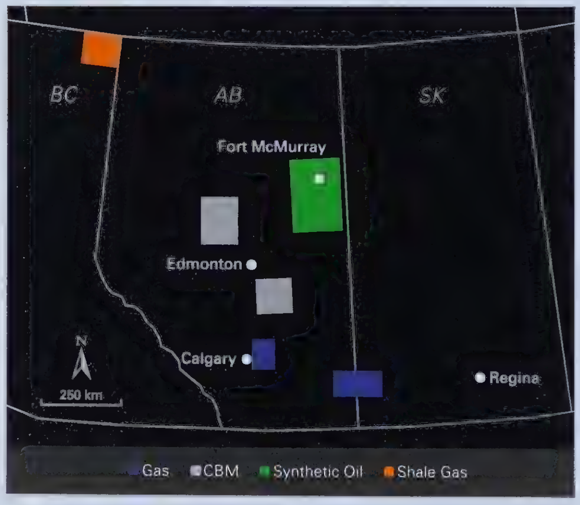
Canada

- We doubled our prospective shale gas acreage in northeast British Columbia in the Horn River, Cordova and Liard basins in 2010.
- We drilled, fraced and completed our recent eight–well pad in the Horn River Basin at an industry-leading pace during the year.



As part of our growth strategy in unconventional Canadian resource plays, we have accumulated over 300,000 acres of highly prospective shale gas lands in northeast British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces and fractures, or absorbed into organic matter.

Our shale gas resource will allow us to take advantage of emerging markets such as growing oil sands demand and potential liquid natural gas (LNG) export opportunities. Shale gas complements our corporate oil and gas portfolio with natural gas exposure and relatively short cycle-time projects where we control the scale and pace of development of the resource. Once our commercial well design is established, we can match the pace of drilling to forecasted economic conditions.



Our Canadian production (excluding the Athabasca oil sands) is comprised of unconventional shale gas assets in northeast British Columbia and conventional producing natural gas and coalbed methane (CBM) assets in Alberta and Saskatchewan. Prior to the sale of our heavy oil assets in July 2010, Canadian production included heavy oil volumes from east-central Alberta and west-central Saskatchewan. Proceeds from the sale were $939 million and the properties were producing approximately 15,000 boe/d. Proved reserves associated with the sold properties were approximately 36 mmboe (30 after royalties).

In addition to our development of the Athabasca oil sands, our strategy for Canada is three-fold: i) significantly expand our shale gas reserves and production; ii) generate new material resource play opportunities; and iii) continue to optimize value from our conventional and CBM producing assets.

SHALE GAS

Approximately 25% of our current Canadian production (excluding Athabasca oil sands) is from our shale gas properties in the Horn River. This basin is a significant shale gas play in northeast British Columbia with high resource density and excellent well productivity. Although historically the United States has been the largest producer of shale gas, new drilling technologies have allowed us to take advantage of vast resource potential in emerging gas plays in Canada.

In 2010, we invested $476 million progressing development of our shale gas assets at Horn River. We drilled and completed an eight–well pad with an average of 18 fracs per well during the year. These wells were completed at an industry-leading pace of 3.5 fracs per day and we achieved a 100% success rate on our fracs. Substantial cost savings and productivity improvements were realized as we leveraged learnings from prior activities to improve equipment utilization, drill longer wells and initiate more fracs per well. We recently started producing these wells and are experiencing initial production rates of 8 to 15 mmcf/d per well. We also commenced drilling a nine–well pad late in 2010 that is expected to be on stream in late 2011.

Following our success at the June 2010 land sale, we increased our position from 128,000 to over 300,000 acres of highly prospective shale gas lands in northeast British Columbia. This includes additional acreage at Cordova and a new position in the Liard basin. We have a 100% operated interest in all of our shale gas properties.

To date, we have invested in land, infrastructure and wells in the Horn River Basin to progress our shale gas strategy toward development and reserve recognition. We have recognized proved undeveloped reserves relating to our existing area of operations.

Primary tenure in the Horn River Basin is four years and drilling activity and extensions can increase this up to 18 years. Our drilling activity to date has secured tenure for ten years on the majority of our Horn River lands at Dilly Creek with drilling currently underway to secure the remainder. With the tenure secured, we are able to control the pace of field development during periods of low gas prices.

Limited gas pipeline infrastructure and processing capacity in the Horn River Basin could potentially constrain early development of the play. To ensure sufficient gathering, processing and transportation capacity for our development programs, we contracted gas pipeline capacity and associated treating capacity at the Spectra-operated Fort Nelson plant. We entered into additional agreements that will allow us to participate in regional infrastructure expansion projects.

OTHER

Conventional natural gas properties in Alberta and Saskatchewan account for 50% of our current Canadian production (excluding Athabasca oil sands). Canadian production includes minimal volumes from sour gas reservoirs near Calgary. Sour gas is natural gas that contains hydrogen sulphide and requires additional processing. This gas is processed through our operated Balzac plant which we plan to decommission in 2011. Remaining gas production from the Balzac field is expected to be processed by third-party gas plants.

Approximately 25% of our current Canadian production is from our CBM developments in the Fort Assiniboine area of central Alberta. We began commercial operations in the Upper Mannville coals in 2005 and progressively developed opportunities on our land base with horizontal well technology. We have limited activity planned here currently as a result of lower natural gas prices.

FISCAL TERMS

In Canada, we pay two types of royalties to federal and provincial governments on production from lands where they own the petroleum and natural gas rights. The first type of royalty, Net Profits Interest (NPI), applies to our oil sands projects and our Horn River shale gas project. The second type is a Gross Royalty system whereby we pay royalties ranging from nil to 50% depending upon drilling date, production rate and product sales price.

The NPI royalty rates for oil sands projects range from 1 to 9% of gross revenue for projects that are pre-payout of costs, and 25 to 40% of net profit for projects that are post-payout. These royalty rates vary depending on the Canadian dollar equivalent of WTI. Royalty rates remain at their floor until Cdn$55/bbl and reach their maximum at Cdn$120/bbl.

In British Columbia, within a designated area, a 2% royalty on project gross revenue is payable to the provincial government until our Horn River shale gas project reaches payout or 10 years pass, whichever is sooner. After that point, royalties are calculated on project net revenue as defined by the province using progressive rates of 15%, 20% and 35%, with a minimum royalty payable of 5% on project gross revenue.

The Gross Royalty system has an upper royalty rate limit to 50% and lower limit to nil, for conventional oil, depending on production rates and sales price. Most of our conventional Alberta production qualifies for lower rates and we expect royalties on our production to range between 5 and 10%.

In 2009, the Alberta government commissioned a Competitiveness Review, which included a review of the provincial royalty system. As a result of this review, the price sensitivity of the royalty curves for natural gas and conventional oil were reduced along with the maximum royalty rates payable from 50% to 36% for natural gas and from 50% to 40% for conventional oil effective January 1, 2011. In addition, any new wells drilled in Alberta pay a maximum royalty of 5% for the first year of production or 500 mmcf of gas or 50,000 bbls of oil, whichever comes first. New CBM wells receive a longer 5% maximum royalty holiday of 3 years or 750 mmcf of production. The result of this review had a small positive impact for the royalties paid on our CBM and conventional gas properties in Alberta.

In addition to royalties, some provinces impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to Crown royalties, ranging from 1.7 to 3.0%. In Alberta, we are subject to a freehold mineral tax of approximately 4% on production from freehold lands.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2010, federal taxable income is taxed at 18% and will be taxed at 16.5% in 2011 and 15% in 2012. Provincial income tax rates vary from approximately 10 to 16%.

ENERGY MARKETING

Our energy marketing group's primary focus is to market proprietary crude oil production from North America, the North Sea and Yemen. We also buy and sell third-party production which provides us with additional market intelligence and opportunities in order to obtain competitive pricing. Our team also leverages regional knowledge, capacity on key North American infrastructure, and solid customer relationships. In addition to physical marketing, we take advantage of quality, time and location spreads to generate returns. We use financial contracts, including futures, forwards, swaps and options for hedging purposes.

In addition to global crude oil marketing activities, we have a North American natural gas and power marketing business. The North American natural gas team's activities are located primarily in western Canada to support our proprietary needs as well as those of other regional producers. The power team is responsible for optimizing and selling power from our Alberta assets including our 50% interest in the Balzac power generation facility; our 50% interest in the Soderglen wind power operation; and surplus power from our cogeneration facility at Long Lake. We also market power to larger commercial, industrial and municipal clients.

During 2010, we concluded the sale of our North American natural gas trading operations, our North Dakota and Montana crude oil lease gathering, pipeline and storage assets, and our European gas and power business.

CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. During 2010, we held a 63.9% interest in our chemicals business.

Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing system is reliable, low-cost and strategically located to capitalize on competitive electricity costs and transportation infrastructure to minimize production and delivery costs.

In 2010, the technology conversion process (TCP) at the North Vancouver chlor-alkali facility was successfully commissioned. The TCP replaced the diaphragm technology with newer, proven membrane technology that is expected to be more cost-effective and expanded productive capacity by 35%.

In early 2011, we sold our interest in this business for net proceeds of $458 million. The sale closed in early February 2011 and we will have no involvement in Canexus after such time. The operations have been presented as discontinued operations in our Consolidated Financial Statements.

RESERVES, PRODUCTION AND RELATED INFORMATION

The following reserves estimates have been prepared in accordance with SEC requirements. In addition to the information below, we refer to the Supplementary Data on page 173 of our 2010 Consolidated Financial Statements for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any Canadian or United States federal authority or agency, any estimates of its total proved oil or gas reserves since the beginning of the last fiscal year.

We have also prepared estimates of reserves and related disclosures in accordance with NI 51-101. This information is contained in the following documents:

- Form 51-101F1 – Statement of Reserves Data and Other Oil and Gas Information
- Form 51-101F2 – Report on Reserves Data by Internal Qualified Reserves Evaluator
- Form 51-101F3 – Report of Management and Directors on Oil and Gas Disclosure

These documents are available on SEDAR at www.sedar.com and are incorporated by reference herein.

Oil and Gas Reserves

The process of estimating reserves requires complex judgments and decision-making. Reserves are categorized by the confidence that they will be economically recoverable. Probable reserves are less certain to be recovered than proved reserves. Refer to the Basis of Reserves Estimates on page 31 for a description of probable reserves and our process for estimating proved and probable reserves.

At December 31, 2010, we had 987 mmboe of proved reserves (918 after royalties) and 1,133 mmboe of probable reserves (995 after royalties).

The following is a summary of our proved and probable reserves as at December 31, 2010:

	Reserves					
	Before Royalties			After Royalties		
	Synthetic Oil	Oil	Gas	Synthetic Oil	Oil	Gas
	(mmbbl)	*(mmbbl)*	*(bcf)*	*(mmbbl)*	*(mmbbl)*	*(bcf)*
Developed	249	167	367	229	161	337
Undeveloped	389	100	127	358	94	122
Total Proved	**638**	**267**	**494**	**587**	**255**	**459**
Developed	21	66	147	17	65	133
Undeveloped	907	90	151	788	79	146
Total Probable	**928**	**156**	**298**	**805**	**144**	**279**

Proved Reserves

In 2010, we added 101 mmboe of proved reserves (107 after royalties), sold 36 mmboe (30 after royalties) associated with our heavy oil properties and produced 89 mmboe (79 after royalties).

The following table provides a summary of the changes in our proved oil and gas reserves before royalties during 2010. Refer to pages 174 and 175 in our Consolidated Financial Statements for proved reserves information on an after–royalty basis.

	Canada						
	Oil Sands						
(mmboe)	Syncrude	Insitu	Other	United Kingdom	United States	Other[1]	Total
December 31, 2009	324	318	81	172	50	66	1,011
Extensions and discoveries	8	3	16	40	–	1	68
Revisions—technical	–	(3)	(3)	30	2	5	31
Revisions—economic	–	–	1	1	(1)	–	1
Acquisitions	–	–	–	1	–	–	1
Divestments	–	–	(36)	–	–	–	(36)
Production	(8)	(4)	(10)	(40)	(10)	(17)	(89)
December 31, 2010	**324**	**314**	**49**	**204**	**41**	**55**	**987**

1 Represents reserves in Yemen, Nigeria and Colombia.

Extensions and discoveries of 68 mmboe (66 after royalties) relate primarily to our discoveries at Golden Eagle, Rochelle and Blackbird in the UK, and the recognition of shale gas reserves from our Horn River development program.

Technical revisions of 31 mmboe (27 after royalties) relate primarily to positive production performance at Buzzard and Telford in the United Kingdom, and in Yemen. These were partially offset by a reduction of reserves at Long Lake due to an adjustment in upgrader PSC™ yield and revised geological mapping resulting from this year's core hole delineation program, as well as performance revisions in our Canadian CBM and gas properties.

Positive economic revisions of 1 mmboe (13 after royalties) reflect changes in average oil and gas prices and costs between 2009 and 2010. The increase primarily reflects higher average oil prices offset somewhat by rising costs. Gas prices did not change significantly from 2009 so there were no related economic revisions in our gas properties. The higher after–royalty economic revisions reflect the impact of higher price-sensitive royalties from our oil sands properties at Long Lake and Syncrude as it takes fewer barrels to satisfy our obligations at higher prices.

The divestment of 36 mmboe (30 after royalties) relates to the sale of our Canadian heavy oil properties for which we received $939 million.

The following provides a summary of the changes in our proved oil and gas reserves before royalties during the past three years. Refer to pages 174 and 175 in our Consolidated Financial Statements for proved reserves information on an after–royalty basis for each of the past three years.

	Canada						
	Oil Sands						
(mmboe)	Syncrude[1]	Insitu	Other	United Kingdom	United States	Other	Total
December 31, 2007	324	268	118	207	62	79	1,058
Extensions and discoveries	23	47	28	65	4	10	177
Revisions—technical	–	(7)	3	52	3	27	78
Revisions—economic	–	–	(26)	(6)	(2)	1	(33)
Acquisitions	–	86	–	1	–	–	87
Divestments	–	–	(36)	–	–	–	(36)
Production	(23)	(9)	(38)	(115)	(26)	(62)	(273)
SEC Rule Transition[2]	–	(71)	–	–	–	–	(71)
December 31, 2010	**324**	**314**	**49**	**204**	**41**	**55**	**987**

1 *We have included Syncrude as oil and gas activity from 2007.*
2 *On December 31, 2008, the SEC issued final revised rules relating to reserves definitions and related disclosure requirements. These new rules were effective for year-end 2009 disclosures.*

Since 2007, we have added 309 mmboe (350 after royalties), sold 36 mmboe (30 after royalties) and produced 273 mmboe (236 after royalties). Extensions and discoveries of 177 mmboe (169 after royalties) occurred primarily at Long Lake, Syncrude, Buzzard, Golden Eagle and our Canadian shale gas properties. The technical revisions of 78 mmboe (63 after royalties) include 52 mmboe (52 after royalties) of positive revisions in the UK, primarily related to better production performance at Buzzard, and 28 mmboe (13 after royalties) from better than expected production performance at Yemen. Negative technical revisions occurred primarily at Long Lake to reflect lease set-back agreements, revised geological mapping and adjustments to our upgrader yield. Negative economic revisions of 33 mmboe (positive 32 after royalties) are primarily related to changes in prices and costs, primarily in our gas properties in Canada and the US. The positive economic revision after royalties reflects the decrease in royalty obligations for oil sands projects which are sensitive to price. Acquisitions of 87 mmboe (86 after royalties) are from our purchase of additional interests in Long Lake and our Telford property in the UK. Divestments of 36 mmboe (30 after royalties) are related to the sale of our Canadian heavy oil properties. The transition to new SEC rules in 2009 caused a reduction of 71 mmboe (83 after royalties) in our Long Lake oil sands property as reserves are now presented as upgraded synthetic oil barrels rather than bitumen barrels.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

The following tables provide proved undeveloped reserves (PUDs) before and after royalties at December 31, 2010 and the changes during 2010:

	Canada						
	Oil Sands						
Before royalties (mmboe)	**Syncrude**	**Insitu**	**Other**	**United Kingdom**	**United States**	**Other**	**Total**
December 31, 2009	116	261	3	28	11	39	458
Extensions and discoveries	7	3	7	40	–	1	58
Revisions—technical	–	2	–	11	(1)	–	12
Revisions—economic	–	–	–	1	–	–	1
Conversions	–	–	–	(17)	–	(1)	(18)
Acquisitions	–	–	–	1	–	–	1
Divestments	–	–	(2)	–	–	–	(2)
December 31, 2010	**123**	**266**	**8**	**64**	**10**	**39**	**510**
PUD %[1]	38%	85%	16%	32%	24%	70%	52%

1 *Determined as a percentage of total proved reserves for that area.*

	Canada						
	Oil Sands						
After royalties (mmboe)	**Syncrude**	**Insitu**	**Other**	**United Kingdom**	**United States**	**Other**	**Total**
December 31, 2009	103	236	2	28	10	34	413
Extensions and discoveries	6	3	7	40	–	1	57
Revisions—technical	–	3	–	11	(1)	–	13
Revisions—economic	5	2	–	1	–	–	8
Conversions	–	–	–	(17)	–	(1)	(18)
Acquisitions	–	–	–	1	–	–	1
Divestments	–	–	(2)	–	–	–	(2)
December 31, 2010	**114**	**244**	**7**	**64**	**9**	**34**	**472**
PUD %[1]	39%	84%	15%	32%	24%	75%	51%

1 *Determined as a percentage of total proved reserves for that area.*

In 2010, our PUDs increased by 52 mmboe (59 after royalties). Extensions and discoveries of 58 mmboe (57 after royalties) relate to our discoveries at Golden Eagle, Rochelle and Blackbird in the UK, a 9-well shale gas pad in the Horn River Basin that is currently being drilled, the addition of another year of production capacity at Syncrude which will come from an undeveloped mine and the addition of lands immediately offsetting our developed lands at Long Lake. The higher after–royalty economic revisions reflect the impact of higher price-sensitive royalties from our oil sands properties at Long Lake and Syncrude as it takes fewer barrels to satisfy our obligations at higher prices. We converted 18 mmboe (18 after royalties) to proved developed, primarily from Buzzard where we converted all of the proved undeveloped reserves associated with the fourth platform, and also from ongoing drilling at Ettrick.

At Syncrude, PUDs of 123 mmboe (114 after royalties) relate to the Aurora South mine that will be required to provide bitumen feedstock to the upgrading facility during its expected life. The mine is part of the Syncrude development plan and was contemplated in the project investment decision relating to the Stage 3 expansion completed in 2005. We do not consider this mine to be developed as the extraction equipment to access the reserves has not yet been installed. We are proceeding with planning for the development of the mine and expect to initiate mine construction in 2016. The PUDs are expected to be converted in eight to ten years when the project is sufficiently developed.

At Long Lake, 266 mmboe (244 after royalties) of PUDs relate to ongoing drilling of the lease to offset declines from the initial SAGD wells. They are expected to be converted over the next 25 years as we drill additional wells to maintain upgrader feedstock. These wells were part of the initial field development plan and were included in the project investment decision.

In the UK, we have 64 mmboe (64 after royalties) of PUDs. Discoveries at Golden Eagle, Rochelle and Blackbird account for 40 mmboe (40 after royalties). The remainder is comprised of 16 mmboe (16 after royalties) at Buzzard for future development wells and 8 mmboe (8 after royalties) at Telford for the tie-in of our successful TAC well and the replacement of a water injection flowline. All of these PUDs are expected to be converted within the next five years.

In our other international operations, 39 mmboe (34 after royalties) of PUDs relate primarily to offshore West Africa. They will be converted in 2012 when construction and commissioning of the FPSO and subsea facilities is completed.

In 2010, we spent $782 million on converting PUDs to proved developed reserves and on those to be converted in future years.

During the year, we converted 18 mmboe (18 after royalties) or about 4% of our PUDs that existed at the end of last year. The conversion rate in 2010 is low because about 90% of the PUDs relate to our Long Lake, Syncrude and Usan projects where conversions take place over 25 years as the wells are needed (Long Lake) or where they are tied to the completion of long cycle–time projects (Syncrude and Usan). Excluding these three projects, we converted 44% of our 2009 PUDs to developed in 2010 and 77% of our PUDs over the last three years. We anticipate that our PUD conversion rate will vary considerably from year to year due to the stage and nature of projects associated with our oil and gas assets. The low conversion rate in 2010 is not necessarily indicative of future PUD conversion rates.

Excluding Long Lake and Syncrude, we expect to convert all of our PUDs to developed in the next five years.

We have reviewed our PUDs and determined there are no material amounts in individual fields which have remained undeveloped for five years or more after they were initially recognized as proved reserves.

We expect our ongoing exploration and development activities to continue to add new PUDs.

Following is a summary of our developed and undeveloped proved oil and gas reserves by country and product at December 31, 2010:

	Before Royalties			**After Royalties**		
	Synthetic Oil	**Oil**	**Gas**	**Synthetic Oil**	**Oil**	**Gas**
	(mmbbl)	*(mmbbl)*	*(bcf)*	*(mmbbl)*	*(mmbbl)*	*(bcf)*
Canada	249	–	246	229	–	231
United Kingdom	–	138	12	–	138	12
United States	–	13	109	–	12	94
Other Countries	–	16	–	–	11	–
Developed	**249**	**167**	**367**	**229**	**161**	**337**
Canada	389	–	47	358	–	44
United Kingdom	–	55	55	–	55	55
United States	–	6	25	–	5	23
Other Countries	–	39	–	–	34	–
Undeveloped	**389**	**100**	**127**	**358**	**94**	**122**
Total Proved	**638**	**267**	**494**	**587**	**255**	**459**

Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves.

At December 31, 2010, we had 1,133 mmboe (995 after royalties) of probable oil and gas reserves. During the year, we added 25 mmboe (40 after royalties), converted 80 mmboe (78 after royalties) and sold 29 mmboe (24 after royalties), resulting in a reduction of 84 mmboe (62 after royalties) in our probable reserves.

The following provides a summary of the changes in our probable oil and gas reserves before and after royalties during 2010:

	Canada						
	Oil Sands						
Before royalties (mmboe)	Syncrude	Insitu[1]	Other	United Kingdom	United States	Other	Total
December 31, 2009	46	888	41	169	24	49	1,217
Extensions and discoveries	8	–	17	6	–	–	31
Revisions—technical	–	(2)	(3)	–	–	(4)	(9)
Revisions—economic	–	(1)	–	1	(1)	–	(1)
Conversions	(8)	(3)	–	(62)	(3)	(4)	(80)
Acquisitions	–	–	–	4	–	–	4
Divestments	–	–	(29)	–	–	–	(29)
December 31, 2010	**46**	**882**	**26**	**118**	**20**	**41**	**1,133**

1 Insitu oil sands reflect our share of the probable reserves at Long Lake and Kinosis.

	Canada						
	Oil Sands						
After royalties (mmboe)	Syncrude	Insitu[1]	Other	United Kingdom	United States	Other	Total
December 31, 2009	41	754	35	169	20	38	1,057
Extensions and discoveries	7	–	17	6	–	–	30
Revisions—technical	–	(2)	(3)	–	–	(3)	(8)
Revisions—economic	2	13	–	1	–	(2)	14
Conversions	(7)	(3)	–	(62)	(3)	(3)	(78)
Acquisitions	–	–	–	4	–	–	4
Divestments	–	–	(24)	–	–	–	(24)
December 31, 2010	**43**	**762**	**25**	**118**	**17**	**30**	**995**

1 Insitu oil sands reflect our share of the probable reserves for Long Lake and Kinosis.

Extensions and discoveries of 31 mmboe (30 after royalties) relate primarily to our Horn River Basin 18-well development pad expected to be drilled in 2011 and exploration successes at Rochelle and Blackbird in the UK. Negative technical revisions of 9 mmboe (8 after royalties) relate primarily to performance revisions in our Canadian conventional gas properties, and geological revisions at Long Lake and our Usan development in Nigeria. The higher after-royalty basis economic revision reflects the impact of price-sensitive royalties from our oil sands properties at Long Lake and Kinosis as it takes fewer barrels at higher prices to satisfy our obligation. Conversions reflect probable reserves converted to proved as a result of increased confidence in producing the reserves based on advancement of development plans, production performance and drilling results. The divestments represent the probable reserves associated with the heavy oil properties we sold.
The acquisition reflects the additional working interest acquired from our partner at Telford.

PROBABLE DEVELOPED AND UNDEVELOPED RESERVES

Following is a summary of our developed and undeveloped probable oil and gas reserves by country and product at December 31, 2010:

	Before Royalties			After Royalties		
	Synthetic Oil	Oil	Gas	Synthetic Oil	Oil	Gas
	(mmbbl)	(mmbbl)	(bcf)	(mmbbl)	(mmbbl)	(bcf)
Canada	21	–	67	17	–	62
United Kingdom	–	58	16	–	58	16
United States	–	5	64	–	5	55
Other Countries	–	3	–	–	2	–
Developed	**21**	**66**	**147**	**17**	**65**	**133**
Canada	907	–	92	788	–	89
United Kingdom	–	50	44	–	50	44
United States	–	2	15	–	1	13
Other Countries	–	38	–	–	28	–
Undeveloped	**907**	**90**	**151**	**788**	**79**	**146**
Total Probable	**928**	**156**	**298**	**805**	**144**	**279**

Developed probable reserves typically reflect increased recovery factors and recompletions of other zones on producing wells. Undeveloped probable reserves reflect reserves that have not yet been drilled or the production facilities completed. They can also represent the reserves associated with higher recovery in proved undeveloped areas.

Approximately 90% of our probable reserves before royalties (90% after royalties) are undeveloped. This primarily reflects the incremental synthetic oil reserves related to future drilling required to keep the upgrader full at Long Lake, the reserves related to the expected development of Kinosis, and the extension of the plant life and expected higher future yields at Syncrude. The remaining undeveloped reserves principally relate to the expected 18-well development pad in the Horn River Basin, undeveloped discoveries at Rochelle and Blackbird in the UK, and Usan and Owowo, offshore West Africa.

Basis of Reserves Estimates

The process of estimating reserves requires complex judgments and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Reserve estimates are categorized by the confidence that they will be economically recoverable. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating conditions and government regulations. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves.

Our reserves estimates are based on internal evaluations. Reserves estimates for each property are prepared at least annually by the property's reservoir engineer and geoscientists, and by divisional management familiar with the property. Our internal reserves evaluation staff consists of over 200 individuals in multifunctional teams with relevant experience in reserves evaluation, engineering and geoscience, and over 150 are qualified reserves evaluators for the purposes of NI 51-101. These individuals are dedicated to the development and operations of the properties evaluated and have a thorough knowledge of them. We support the technical staff with up-to-date tools for geological mapping, seismic interpretation, reservoir simulation and other technical analysis. Our reserves processes are designed to use all available information to provide accurate estimates for internal business needs and external reporting requirements.

Our internal qualified reserves evaluator (IQRE) is responsible for the reserves data and related disclosures. This position, required under NI 51-101, was appointed by the Board in December 2003. The IQRE is a professional engineer and meets all professional and statutory requirements in regards to experience, education and professional membership associated with the role. With over 28 years of experience, he has an in-depth knowledge of reserves estimation techniques and professional guidelines, and SEC and Canadian reserves regulations and related reporting requirements. His primary duty includes assessing whether the reserves estimates and related disclosures have been prepared in accordance with applicable regulatory requirements.

We have adopted a corporate policy that prescribes the procedures and standards to be followed in the evaluation of our reserves. This policy is reviewed and amended annually as required to conform to changes in law or industry accepted evaluation practices.

We have at least 80% of our oil and gas reserves either evaluated or audited annually by independent qualified reserves consultants using SEC requirements. Given that reserves estimates are based on numerous assumptions, interpretations and judgments, differences frequently arise between the estimates prepared by different qualified estimators. When the initial estimate of proved reserves on the portfolio of properties differs by greater than 10%, we work with the independent reserves consultant to reconcile the difference to within 10%. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively. We do not attempt to resolve each property to within 10% as it would be time and cost prohibitive given the number of wells in which we have an interest. We follow a similar process in connection with our probable reserves estimates whereby we reconcile any differences on a proved plus probable basis to be within 10%, and as such, probable reserves for individual properties within the portfolio may differ significantly.

An Executive Reserves Committee, including our CEO, CFO and IQRE, meet with divisional reserves personnel to review the estimates and any changes from previous estimates. The Board of Directors has a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent and familiar with estimating oil and gas reserves and disclosure requirements. The Reserves Committee meets with management periodically to review the reserves process, the portfolio of properties selected by management for independent assessment, results and related disclosures. The Reserves Committee appoints and meets with the IQRE and independent reserves consultants, independent of management, to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the

independent reserves consultants, their independence. In the event of a proposed change to the areas of responsibility of either an independent reserves consultant or the IQRE, the Reserves Committee inquires whether there have been disputes between the respective party and management.

The Reserves Committee has reviewed our procedures for preparing the reserves estimates and related disclosures and the properties selected by management for independent assessment. The Committee reviewed the information with management, and met with the IQRE and the independent qualified reserves consultants. As a result, the Reserves Committee is satisfied that the internally generated reserves estimates are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the Board has approved the reserves estimates and related disclosures in this AIF.

The following provides an overview of the nature and scope of the independent evaluations and audits that we have performed. An independent evaluation is a process whereby we request a third-party engineering firm to prepare an estimate of our proved and probable reserves by assessing and interpreting all available data on a reservoir. An independent audit is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by reviewing our estimates, supporting working papers and other data as they feel is necessary. The primary difference is that an auditor reviews our work and estimate in preparing their estimate, whereas an evaluator uses the reservoir data to prepare their own estimate.

In each case, we request their estimates to be prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC requirements. Generally recognized methods for estimating reserves include volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs and reservoir simulation. The method or combination of methods used is based on their professional judgment and experience. In preparing their estimates, they obtain information from us with respect to property interests, production from such properties, current costs of operations, expected future development and abandonment costs, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data. They may rely on the information without independent verification. However, if in the course of their evaluation they question the validity or sufficiency of any information, we request that they not rely on such information until they satisfactorily resolve their questions or independently verify such information.

We do not place any limitations on the work to be performed. Upon completion of their work, the independent reserves consultant issues an opinion as to whether our estimates of the proved and probable reserves for that portfolio of properties is, in aggregate, reasonable relative to the criteria set forth in the SEC and Financial Accounting Standards Board requirements.

For our reserves estimates prepared in accordance with SEC requirements, we engaged three independent reserves consultants to evaluate or audit our properties:

- We engaged DeGolyer and MacNaughton (D&M) to evaluate 97% of our proved and 96% of our proved plus probable reserves in the United Kingdom, Nigeria, Yemen and our Canadian shale gas properties. D&M provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.
- We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate approximately 100% of our proved and our proved plus probable reserves for our Canadian conventional, CBM and insitu oil sands properties. McDaniel provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.
- We also engaged McDaniel to audit 100% of our proved and proved plus probable reserves for our Syncrude interest. McDaniel provided an opinion that the proved and proved plus probable reserves estimates for the Syncrude property are reasonable because they expect it would be within 10% of their own estimate were they to perform their own detailed evaluation of the property.
- We engaged Ryder Scott Company (Ryder Scott) to evaluate 93% of our proved and 95% of our proved plus probable US Gulf of Mexico properties. Ryder Scott provided an opinion that the proved and proved plus probable reserves for the reviewed properties are reasonable because, in aggregate, they are within 10% of their estimates.

For each opinion, a Report of Third Party has been prepared, which summarizes the work undertaken, the assumptions, data, methods and procedures they used and concludes with their opinion. These reports have been filed on SEDAR at www.sedar.com.

Special Note to Canadian Investors

Nexen has received an exemption from the securities regulatory authorities in the various provinces of Canada, that permits us to prepare our reserves estimates and disclosures in accordance with SEC requirements in this AIF. As discussed on page 25, reserves estimates and disclosures prepared in accordance with NI 51-101 have been filed on Form 51-101F1 at the same time as this AIF on SEDAR and are incorporated by reference herein.

As a result of this exemption, Nexen's disclosures may differ from other Canadian companies and investors should note the following fundamental differences between reserves estimates and related disclosures prepared in accordance with SEC requirements and those prepared in accordance with NI 51-101:

- SEC reserves estimates are based upon different reserves definitions and are prepared in accordance with generally recognized industry practices in the US, whereas NI 51-101 reserves are based on definitions and standards promulgated by the Canadian Oil and Gas Evaluation (COGE) Handbook and generally recognized industry practices in Canada;
- SEC reserves definitions differ from NI 51-101 in areas such as the use of reliable technology, areal extent around a drilled location, quantities below the lowest known oil and quantities across an undrilled fault block;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using the year's monthly average prices and costs held constant, whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecast prices and costs;
- the SEC mandates disclosure of reserves by geographic area, whereas NI 51-101 requires disclosure of reserves by additional categories and product types;
- the SEC does not require the disclosure of future net revenue of proved and proved plus probable reserves using forecast pricing at various discount rates;
- the SEC requires future development costs to be estimated using existing conditions held constant, whereas NI 51-101 requires estimation using forecast conditions;
- the SEC does not require the validation of reserves estimates by independent qualified reserves evaluators or auditors, whereas, without an exemption noted below, NI 51-101 requires issuers to engage such evaluators or auditors to evaluate, audit or review their reserves and related future net revenue; and
- the SEC does not allow proved and probable reserves to be aggregated, whereas NI 51-101 requires issuers to do such aggregation.

The foregoing is a general description of the principal differences only. The differences between SEC requirements and NI 51-101 may be material for certain properties.

Nexen has also received an exemption from NI 51-101 that permits us to forego the requirement to have our reserves and related future net revenue evaluated, audited or reviewed by an independent qualified reserves evaluator or auditor. Accordingly, our future net revenue and reserves estimates are based on internal evaluations. Due to the extent and expertise of our internal reserves evaluation resources, our staff's familiarity with our properties and the controls applied to the evaluation process, we believe the reliability of our internally generated reserves estimates is not materially less than would be generated by an independent reserves evaluator.

Net Sales by Product from Oil and Gas Operations[1]

(Cdn$ millions)	2010	2009	2008
Conventional Crude Oil and Natural Gas Liquids (NGLs)	4,121	3,605	5,534
Synthetic Crude Oil	978	480	691
Natural Gas	411	316	652
Total	**5,510**	**4,401**	**6,877**

1 *Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).*

Crude oil (including synthetic crude oil) and NGLs represent approximately 93% of our oil and gas net sales, while natural gas represents the remaining 7%.

Sales Prices and Production Costs

	Average Sales Price[1]			Average Production Cost[1]		
	2010	2009	2008	2010	2009	2008
Crude Oil and NGLs (Cdn$/bbl)						
Oil Sands—Syncrude	81.23	70.96	105.47	39.78	39.09	42.04
Oil Sands—Insitu	77.07	–	–	105.17	–	–
Canada—Other	61.39	53.04	74.51	20.97	20.82	22.16
United Kingdom	79.02	67.70	96.23	8.24	6.87	6.75
United States	76.73	65.01	104.94	10.76	14.10	13.48
Yemen	81.86	68.49	99.87	18.69	18.34	15.88
Other Countries	76.83	59.05	98.98	7.52	6.53	4.91
Natural Gas (Cdn$/mcf)						
Canada	3.94	3.78	7.73	1.93	1.92	2.09
United Kingdom	5.28	3.95	6.78	1.38	1.15	1.12
United States	4.97	4.67	10.07	1.79	2.35	2.25
Corporate Average (Cdn$/boe)	**70.11**	60.02	89.78	**17.62**	13.33	13.18

1 *Sales prices and unit production costs are calculated using our working interest production after royalties.*

Oil and Gas Acreage

	Developed		Undeveloped[1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Oil Sands—Insitu	14	9	675	281	689	290
Oil Sands—Syncrude	68	5	180	13	248	18
Canada—Other	624	471	1,146	774	1,770	1,245
United Kingdom	219	104	1,435	985	1,654	1,089
United States	205	108	1,201	591	1,406	699
Yemen[2]	47	26	777	649	824	675
Colombia[3]	2	–	676	591	678	591
Nigeria[2, 4]	–	–	678	131	678	131
Norway	–	–	627	301	627	301
Total[5]	1,179	723	7,395	4,316	**8,574**	**5,039**

1 *Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.*
2 *The acreage is covered by production-sharing contracts.*
3 *The acreage is covered by an association contract.*
4 *The acreage is covered by joint venture agreements.*
5 *Approximately 29% of our net oil and gas acreage is scheduled to expire within three years if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licences.*

Producing Oil and Gas Wells

(number of wells)	Oil Gross[1]	Oil Net[2]	Gas Gross[1]	Gas Net[2]	Total Gross[1]	Total Net[2]
Canada	107	63	2,784	2,500	2,891	2,563
United Kingdom	64	31	–	–	64	31
United States	79	45	71	48	150	93
Yemen	472	274	–	–	472	274
Colombia	110	11	–	–	110	11
Total	832	424	2,855	2,548	**3,687**	**2,972**

1 *Gross wells are the total number of wells in which we own an interest.*
2 *Net wells are the sum of fractional interests owned in gross wells.*

Drilling Activity

2010

	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Canada	9.0	–	9.0	21.5	–	21.5	30.5
United Kingdom	2.0	1.3	3.3	5.3	0.4	5.7	9.0
United States	0.5	–	0.5	0.8	–	0.8	1.3
Other Countries	–	0.7	0.7	12.6	0.5	13.1	13.8
Total	**11.5**	**2.0**	**13.5**	**40.2**	**0.9**	**41.1**	**54.6**

2009

	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Canada	8.1	–	8.1	56.8	–	56.8	64.9
United Kingdom	3.1	1.3	4.4	5.7	0.8	6.5	10.9
United States	0.7	0.2	0.9	1.0	–	1.0	1.9
Other Countries	0.2	–	0.2	14.0	–	14.0	14.2
Total	**12.1**	**1.5**	**13.6**	**77.5**	**0.8**	**78.3**	**91.9**

2008

	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Canada	9.2	–	9.2	216.4	–	216.4	225.6
United Kingdom	2.5	2.0	4.5	3.3	–	3.3	7.8
United States	0.5	1.0	1.5	1.3	–	1.3	2.8
Other Countries	–	1.0	1.0	19.0	–	19.0	20.0
Total	**12.2**	**4.0**	**16.2**	**240.0**	**–**	**240.0**	**256.2**

Wells in Progress

At December 31, 2010, we were drilling one well in the United Kingdom (0.4 net), 2 wells in Canada (1.3 net) and one well in Yemen (0.5 net). There were no wells drilling in the United States, Colombia, Nigeria or Norway at December 31, 2010.

ENVIRONMENTAL AND REGULATORY MATTERS

Government and Environmental Regulations

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to exploration, production practices, occupational health and safety, environmental protection, midstream and marketing activities. These laws and regulations may increase the cost of doing business and, accordingly, affect profitability. We participate in many industry and professional associations through which our interests in new regulations and legislation are represented, and we monitor the progress of proposed regulatory and legislative amendments.

Laws and regulations change frequently and sometimes unpredictably. Regulatory complexity and stringency has increased over the past several years, as has the cost of compliance. Based on this trend, it is reasonably likely that the costs of compliance will continue to increase. We consider compliance with these regulations a necessary and manageable part of our business. We have been able to plan for and manage the increasing regulatory requirements without materially changing our business strategies or incurring significant or unreimbursed expenditures, though we are unable to predict the impact of future changes in compliance requirements on costs. We do not expect that the effect of these laws and regulations on our operations will be materially different than they would for any other oil and gas company of similar size and financial strength. We believe our operations comply, in all material respects, with applicable laws and regulations in the various jurisdictions where we operate.

The types of laws and regulations that affect our business most significantly fall into two categories: i) Operational and ii) Health, Safety and Environmental.

OPERATIONAL REGULATIONS

Our oil and gas exploration and production activities are subject to various international, federal, state, provincial, territorial and local laws and regulations. Those laws and regulations affect a number of operational activities, including:

- land access;
- acquisition of seismic data;
- location of wells;
- drilling, completion and well servicing;
- transportation, storage and disposal of waste products arising from oil and gas operations;
- land restoration and well abandonment;
- pricing policies;
- royalties;
- various taxes and levies including income tax; and
- foreign trade and investment.

The implications of these laws and regulations to our business include direct costs in the form of tariffs, fees, taxes, rent and royalties and other direct charges measured by the type, region or intensity of activity. Indirect costs also arise from restricted access to certain areas of operation; restrictions on the type, frequency or conduct of permitted oilfield operations; limitations on production rates from certain oil and gas wells; forced pooling of oil and gas interests with third parties; changes in drill spacing units or well densities; infrastructure development; satisfaction of local content obligations for international projects; carried government participation in certain projects; and community consultation.

Gulf of Mexico

Throughout the second half of 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service of the Department of the Interior) released new regulations governing drilling activities in the Gulf of Mexico. These regulations contain, among other things, increased requirements for wellbore integrity, blow-out prevention, well control equipment, personnel training, rig safety and spill response. We are currently assessing the cost of compliance associated with these regulations, however we do not anticipate any difficulty meeting them. We believe that the rigorous health, safety and environmental processes that we apply to our existing offshore operating activities will enable us to satisfy these new regulatory obligations. Despite our ability to meet the new regulations, the new processes implemented by the Bureau to administer these regulations are expected to result in significant delays in the permitting process, which could add to costs and longer cycle times for our Gulf of Mexico exploration and development drilling activities.

The United States Government remains at an impasse as to what extent the oil and gas industry should be held responsible for future oil spills. The 111th Congress adjourned at the end of 2010 with no oil spill legislation passing into law. We anticipate that the 112th Congress will review requirements of financial responsibility and third-party liability caps and we expect some legislation to pass in these areas.

HEALTH, SAFETY AND ENVIRONMENTAL REGULATIONS

Our oil and gas operations are subject to various international, federal, state, provincial, territorial and local laws and regulations designed to regulate the impact of human activity on the natural environment and the safety of our worksites. These laws and regulations relate to:

- the types and quantities of substances and waste materials that can be discharged into the environment;
- use or removal of natural resources (such as water and timber) in exploration and production activities;
- abandonment, reclamation and remediation of worksites (including sites of former operations);
- development of emergency and community response plans; and
- implementation of safe work practices for employees and contractors.

We are committed to operating within these laws and regulations and to conducting our business in a safe and environmentally responsible manner.

Environmental regulation is becoming more complex and increasingly stringent. To reduce our risk of non-compliance with these laws, we apply industry standards, codes and best practices that meet or exceed our legal obligations. We conduct activities in countries where environmental regulatory frameworks are in various stages of development. Where regulations do not exist, or where we consider them to be insufficiently developed, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

Our Health, Safety, Environment and Social Responsibility group (HSE&SR) helps ensure our worldwide operations are conducted in a safe, ethical and socially responsible manner. Our HSE&SR practices are reported to our Board of Directors throughout the year and comprise part of our formal integrity and ethics reporting processes. Nexen's overall HSE&SR program is guided by our corporate HSE&SR management system that incorporates the Responsible Care continual improvement model of Plan, Do, Check, Act and our own 12 guiding elements for divisional performance. For more information on Nexen's HSE&SR governance model, refer to our sustainability report available at www.nexeninc.com. For more information on Responsible Care, please refer to our sustainability report and www.ccpa.ca.

Our performance against this system is reviewed by an external auditor every three years, and we have been recognized by the Goldman Sachs Sustain Report and Dow Jones Sustainability Index (North America) as a sustainability leader. Our progress is publicly reported in our sustainability report.

Environmental and Social Responsibilities

Environmental and social responsibility has become an increasingly significant measurement of corporate performance by governments, investors and the public. The oil and gas industry is being challenged to improve its response to the effects of climate change, embrace responsible operating practices, including the preservation of water and land, and invest in the communities it relies upon to do business. The level of regulation associated with

these issues varies considerably throughout the jurisdictions in which we operate. Based on the current trend it is reasonably likely that our regulatory obligations and the associated cost of compliance will increase. Due to the uncertainty surrounding the future implementation of regulations, we are unable to estimate our costs of compliance in the future.

As a result of our commitment to responsible operating practices and social responsibility, we believe we are well positioned to meet the challenges of increasing environmental regulation and social expectations that have become a significant component of sustainable resource development. We have built a corporate culture of integrity and respect for the communities and environments in which we operate and have developed policies and practices for continuing compliance with all environmental laws and regulations.

CLIMATE CHANGE

Nexen believes that climate change and the transition to a low carbon energy system are important issues. For the past decade, Nexen has been active in planning and preparing for carbon regulation and has been engaged in public discussions on this matter in jurisdictions where we operate. We have also participated in carbon markets, renewable energy initiatives and a range of carbon offset/crediting projects. We currently manage compliance for our four producing assets in the UK sector of the North Sea and in our operations in Canada (located in the provinces of Alberta, Saskatchewan and British Columbia). The Canadian federal government has yet to pass climate change legislation. In 2010, the Canadian and US governments introduced new fuel efficiency standards for the light duty vehicle fleet and the Canadian Federal government has reached agreement with the coal-fired electricity sector in respect of the treatment of the existing coal-fired generation. Canada has previously announced their intent to mirror US legislation in this area but recently indicated they did not have to wait if their best interests were served by unilateral action. In the US, there has been no progress on comprehensive climate/energy legislation and President Obama has indicated it is unlikely his administration will pursue such legislation before the next presidential election in 2012.

Any required reductions in the greenhouse gases (GHGs) emitted from our operations (without an allowed offset compliance mechanism) could result in increases to our capital or operating expense, or reduced operating rates, especially at the Long Lake project, which could have an adverse effect on our results of operations and financial condition. As a "new facility", Long Lake will have three years to establish an emissions baseline before having a reduction obligation assigned. In 2010, our Canadian operations, including Syncrude, accounted for 27% of our production before royalties.

Alberta became the first jurisdiction in Canada to enact and implement binding economy-wide emission reductions (a one-time from base, 12% reduction in carbon intensity vs. a 2005 baseline) on facilities annually emitting more than 100 kilo-tonnes of CO_2 equivalent. Facilities unable to achieve internal reductions have an unlimited ability to pay into a technology fund at the rate of $15 per tonne of CO_2 equivalent. This amount must be paid annually until such time as internal reduction is achieved unless other approved offsets are acquired from projects in Alberta.

British Columbia enacted legislation in November 2007 titled the *Greenhouse Gas Reduction Targets Act*, which targets a 33% reduction in current provincial GHG emissions by 2020. British Columbia is actively engaged in the Western Climate Initiative and recently enacted a GHG reporting regulation. For oil and gas operations, the facility emission reporting threshold is zero (i.e., all facilities must report regardless of size). The province also applied a carbon tax to all hydrocarbon fuels sold in the province. The tax started at $10/tonne of CO_2 in 2008 and will increase $5 per year; it will reach $30 per tonne in 2012.

It remains to be seen if the federal and provincial governments will harmonize their compliance regimes in Canada.

In 2008, the European Union (EU) introduced Phase II of the Emissions Trading Scheme (ETS), which will run until the end of 2012. Under Phase II of the ETS, member states were required to establish a national allocation plan approved by the EU. The system covers CO_2 from certain combustion and flaring activities, and member states are allowed to manage allocation across their industrial base as they see fit. Installations have the ability under the ETS to purchase allowances or other eligible instruments to ensure compliance. Phase III, scheduled to run from 2013 to 2020,

may include a transition from the gratis allocation of allowances to the use of auctioning. Post-2012 auctioning of allowances for all electricity generation activities and phased reduction of free allocation of allowances for other activities, as well as phased reduction of allowance availability in general, are expected to increase our annual cost of compliance. Proposals to increase the EU reduction obligation from 20 to 30%, if implemented, could also increase annual cost of compliance.

In 2009, the US Environmental Protection Agency (EPA) announced its findings that GHGs pose a threat to public health. In the absence of other federal programs to regulate GHGs, the EPA has initiated regulatory activity under the authority of the Clean Air Act. The facility threshold for this action is currently set at 25,000 tonnes per year, a level that none of our operated US facilities currently emits. The EPA has expressed interest in regulating smaller GHG sources, though the agency has yet to fully implement its regulation of the larger sources and no regulatory proposals have been finalized. The impact of EPA activity in the area of GHG regulation is expected to be minimal on our operations in the Gulf of Mexico.

Conference of Parties 16 in Cancun failed to achieve any meaningful progress on a post-2012 international agreement to reduce global GHGs. Progress was made on some administrative matters, but important details remain to be negotiated in Durban, South Africa in December 2011. There have been no changes to pledges made by Canada (or other countries where we operate) under the Copenhagen Accord. The Cancun Agreement affirms the goal of limiting global temperature increases to less than 2°C and states that parties consider limiting any increase to no more than 1.5°C.

The Kyoto Protocol does not expire, but the first commitment period expires at the end of 2012. In the absence of progress on a second commitment period the current obligations remain in place. The US did not ratify the Kyoto Protocol and as such has no commitment and Canada has indicated they will not make their target by 2012. In the absence of a second commitment period it is unclear what implications there are for Canadian non–compliance.

The Canadian Council of Ministers of the Environment (the CCME is comprised of the federal and provincial ministers) decided in 2010 to pursue regulation of air pollutants and has established a work plan for 2011 with the expressed intent of proclaiming regulations in 2012. While we could face technical challenges in meeting minimum emission standards for certain pollutants, we are unable at this time to project the cost of compliance and impact on our operations, but believe them to be immaterial.

To meet our current and projected GHG emissions obligations, we continue to pursue a four-point emissions management strategy:

- reduce direct GHG emissions at our facilities;
- self-generate carbon credits from wind power;
- acquire carbon credits through qualified projects and authorized agencies; and
- participate in eligible international and domestic offset projects.

WATER

We have developed a water strategy designed to minimize water use in our exploration and production operations. This strategy is embodied by the following four principles:

- optimize water use efficiency;
- minimize our impacts on ecosystem functions and ensure public health and safety are not affected by our activities;
- engage with stakeholders to promote responsible watershed management and evaluate opportunities to provide water management benefits to stakeholders; and
- measure and communicate our water management performance.

This strategy was implemented in 2009 with an emphasis on compliance and early adoption of best practices, incorporating water assessment tools in our investment decision-making process and developing water management systems to enhance water tracking and reporting. Our water data management project, which starts in 2011, will provide us with information we can use to improve water efficiency.

LAND AND BIODIVERSITY

Our land use practices are based upon principles of minimal disturbance and a commitment to return land to its natural state after responsibly producing oil and gas resources. We also recognize our ability to effectively access land is directly linked to the way in which we manage the potential environmental impact and in how we cooperate with local communities, stakeholders, regulators and other industries to reduce the cumulative effect of our projects throughout their life–cycle.

For many stakeholders, a company's ability to meet environmental expectations is a significant criteria upon which their decision to invest or conduct business is based. A failure to meet those expectations can limit access to exploration, development and partnership opportunities. Therefore, we believe that superior environmental and social responsibility performance is directly linked to economic performance.

We have outlined and more fully discussed our environmental practices and policies in our sustainability report, available on our website at www.nexeninc.com.

COMMUNITY INVESTMENT

Giving back to the communities in which we operate is a deeply rooted value at Nexen. The Company's "ReachOut — Giving, Matching, Helping" community involvement strategy supports the priorities of our employees and communities while providing a strategic link to our business. We have prioritized five core areas for the Company's community investment dollars: Education; Employee Matching; Arts and Culture; Community Development; and Aboriginal Partnerships. Details regarding Nexen's community investment initiatives are available in our sustainability report.

Environmental Provisions and Expenditures

Meeting the challenges of climate change and environmental regulation and our commitment to sustainable resource development affects all stages of our operations and generally increases their cost. Environmental commitments and regulation can increase the operating or capital cost of operations, delay requisite permits or approvals from issuing authorities and result in unprofitable or unfavourable operating conditions. During 2010, we incurred both capital and operational expenses, including expenses related to environmental control facilities. Those costs were not material and did not impair our ability to execute our business or operating strategy. We will continue to incur these costs in the future and expect they will be manageable. At December 31, 2010, $1,064 million ($2,552 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations.

EMPLOYEES

We had 3,925 employees on December 31, 2010.

RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in the oil and gas industry and some of which are unique to our operations. Certain risks set out below constitute "forward-looking statements" and the reader should refer to the special note regarding "Forward-Looking Statements" set out on page 1 of this AIF.

Our profitability and liquidity are highly dependent on the price of crude oil and natural gas.

Our financial performance depends significantly on the price of crude oil and natural gas. Extended periods of lower commodity prices may reduce our level of spending for oil and gas exploration and development, and materially adversely affect our results of operations. Lower commodity prices could also have a material adverse effect on our estimates of proved reserves, the carrying value of our oil and gas properties, the level of planned drilling activities and future growth. Crude oil and natural gas are commodities that are sensitive to numerous worldwide factors, many of which are beyond our control. These factors include, but are not limited to:

- global supply and demand for crude oil, natural gas, and natural gas liquids;
- the costs of exploring for, developing, producing, and transporting crude oil, natural gas and natural gas liquids;
- weather conditions;
- the effect of energy conservation efforts;
- the pricing and availability of alternative fuels and energy;
- production quotas set by the Organization of Petroleum Exporting Countries (OPEC) and their ability to meet those quotas;
- worldwide geopolitical events, armed conflict and acts of terrorism;
- domestic and foreign government regulations and taxes; and
- the overall economic environment worldwide.

Increased environmental regulation could increase our operating costs and affect profitability.

Our oil and gas operations are subject to various international, federal, state, provincial, territorial and local laws and regulations designed to regulate the impact of human activity on the natural environment. Those laws and regulations govern, amongst other things:

- the types and quantities of substances and waste materials that may be discharged into the surface and sub-surface environment;
- the use or removal of natural resources (such as water and timber) in exploration and production activities;
- the release of greenhouse gases, such as carbon dioxide and methane, into the atmosphere;
- the protection of endangered species;
- the abandonment, reclamation and remediation of worksites (including sites of former operations);
- the issuance of permits and other regulatory approvals in connection with exploration, drilling and production activities; and
- the issuance of permits and other regulatory approvals in connection with the construction of roads, pipelines and other regional transportation infrastructure.

These laws and regulations may impose significant liabilities on a failure to comply with their requirements. Significant changes in the environmental laws and regulations governing our current operations, including many of the proposed initiatives to regulate greenhouse gas emissions, may have an adverse effect on the oil and gas industry, including our company. The cost of meeting new environmental and climate change regulations may have an adverse effect on the viability of future projects, our results of operations, cash flows and financial condition.

Negative public perception of oil sands development may harm our corporate reputation.

Development of the Athabasca oil sands has figured prominently in recent political, media and activist commentary on the subject of climate change, greenhouse gas emissions, water usage and environmental damage. Concerns over heightened greenhouse gas emissions and water and land use practices in oil sands developments may directly or indirectly harm the profitability of our current oil sands projects and the viability of future oil sands projects in a number of ways, including:

- creating significant regulatory uncertainty that challenges economic modeling of future projects and potentially delays sanctioning;
- motivating extraordinary environmental and emissions regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment; and
- compelling legislation or policy that limits the purchase of crude oil produced from the Athabasca oil sands by governments or other institutional consumers that, in turn, limits the market for this crude oil and reduces its price.

Concerns over these issues may also harm our corporate reputation and limit our ability to access land and joint venture opportunities in other jurisdictions throughout the world.

Deep-water operations involve additional risk.

Our deep-water operations take place in difficult and unpredictable environments and are subject to the risk of blowouts and other catastrophic events that could result in suspension of operations, damage to equipment, harm to individuals and damage to the environment. While various precautions are taken to reduce the risk, these efforts cannot eliminate the risk that such events may occur.
The consequences of catastrophic events occurring in deep-water operations can be more difficult and time-consuming to remedy. As well, the remedy may be made more difficult or uncertain by the water depths, pressures and cold temperatures encountered in deep-water operations, shortages of equipment and specialists required to work in these conditions, or the absence of appropriate means to effectively remedy such consequences. Emergency response plans that we have in place to address the environmental impact from spills, leaks, blowouts or other events in connection with our operations may not be entirely effective in mitigating the consequences of blowouts or other catastrophic events. Our deep-water operations could also be affected by the actions of our contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic

events occurring at third-party deep-water operations. In either case, this could give rise to liability for us, damage to our equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations. It is possible that the allocation of liabilities and risk of loss arising from deep-water operations and associated insurance coverage will not be sufficient to address the costs arising out of such events.

The costs in connection with a blowout or other catastrophic event could be material and we may not maintain sufficient insurance to address such costs. As it pertains to these types of deep-water risks, we maintain insurance for costs relating to property damage to our facilities, control of well including drilling relief wells, removal of wreck, pollution clean–up, liability for bodily injury and property damage to third parties, including our contractors, and liability for damage to natural resources.

For property damage to our facilities, we are covered for amounts up to the replacement cost of those facilities. For control of well, pollution clean–up, liability for bodily injury and property damage to third parties caused by pollution, we are insured for amounts up to US$350 million. We have separate, additional insurance covering liability for bodily injury and property damage to third parties of up to US$450 million, which responds whether the liability arises from pollution or from other causes. Where we are the operator of a well or a facility, we are insured for our working interest share of US$35 million of coverage relating to our obligations under Section 1001 of the US Oil Pollution Act of 1990, which includes liability for damage to natural resources. For declared deep-water wells, we are insured for our working interest share of US$250 million for costs related to control of the well. Our insurance for "pollution clean–up" covers: i) reasonable and necessary expenses incurred; ii) liability to any governmental entity for clean-up and removal costs and expenses; and iii) liability for costs and expenses of governmental action. In each case we are covered to the extent reasonable and necessary to minimize or remediate, or prevent further, injuries to persons or loss or damage to the property of others arising out of seepage, pollution or contamination. Our insurance for "liability for damage to natural resources" covers sums for which we may be liable as a result of loss of or damage to, including loss of use of, "natural resources" arising out of seepage, pollution or contamination. "Natural resources" include land, fish, wildlife, plantlife, air, water, ground water, drinking water supplies and other such resources.

The 2010 explosion and sinking of the deep-water Horizon rig in the Gulf of Mexico and the resulting oil spill have resulted in increased scrutiny of deep-water operations by governments, environmental groups, investors and the general public, not only in the United States but globally. It is anticipated this will result in increased regulation of deep-water operations, increased cost of compliance with applicable laws and greater difficulty in permitting deep-water operations. There is also a risk that liability limits under existing regulations could be increased substantially by the US Government, which would increase our potential liability in the event of a blowout or other catastrophic event. We also may not be able to access sufficient pooled liability funds set up in the Gulf of Mexico for costs of a blowout or other catastrophic event.

Catastrophic events in connection with our deep-water operations, such as blowouts and oil spills, could result in material costs and reputational damage, and could have a material adverse impact on our credit rating, our ability to raise capital or the cost of such capital.

Exploration, development and production activities may not be successful and carry a risk of loss.

Acquiring, developing and exploring for oil and natural gas involves many risks. There is a risk that we will not encounter commercially productive oil or gas reservoirs and that the wells we drill may not be productive or not sufficiently productive to recover a portion or all of our investment. We may not achieve production targets should our reservoir production decline sooner than expected. Seismic data and other exploration technologies we use do not provide conclusive proof prior to drilling a well that crude oil or natural gas is present or may be produced economically. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be extended, curtailed, delayed or cancelled as a result of a variety of factors, including:

- encountering unexpected formations or pressures;
- blowouts, wellbore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- accidents and equipment failures;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

These occurrences may also result in damage to or destruction of wells, facilities or other property, pollution, injury to persons or loss of life. We operate a sour gas processing facility that is located in close proximity to populated areas and processes materials of potential harm to the local population.

We may not be fully insured against all of these risks, and insurance may not be available for certain risks, such as named wind storms. Our contractual allocation of risk amongst joint-operating partners and service providers may not operate as intended. Losses resulting from the occurrence of these risks may materially impact our operational activities and financial results.

Unconventional gas resource plays carry additional risks and uncertainties.

Part of Nexen's growth strategy is to invest in unconventional gas resource plays, such as shale gas and CBM. Exploitation techniques and practices for these resources are generally in the early stages of development and it is difficult to determine whether or not these resource plays will prove commercially viable, to what degree or when.

Shale gas is an unconventional gas produced from reservoirs composed of organic rich shales. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Some of the uncertainties associated with development of shale gas resources are as follows:

- shale gas wells typically have higher initial production decline rates than conventional gas wells, although this varies by area;
- regulatory approval is required to drill more than one well per section, resulting in uncertainty in the timing of drilling programs and land development;
- shales are typically less permeable than conventional gas reservoirs and can therefore require more extensive, and expensive, completion technologies, which can increase costs or which may not be successful;
- seasonal access to certain areas may limit activities or increase competition for equipment and/or qualified personnel;
- lack of access to regional infrastructure for the sale of production; and
- significant capital expenditures are required before establishing commerciality of a particular play.

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal seam. Some of the uncertainties associated with development of CBM resources are as follows:

- if the coalbed is water-saturated, such as the Mannville coals in the Fort Assiniboine region of Alberta, water generally needs to be extracted to reduce the pressure and allow gas production to occur. A significant period of time may be required to de-water these wet coals and

determine if commercial production is feasible. We may also have to invest significant capital in these assets before they achieve commercial rates of production, if ever;

- some coalbeds may not have sufficient natural permeability in the coalbed to recover the gas in place and can therefore require more extensive, and expensive, completion technologies, which can increase the cost of drilling and production or which may not be successful;
- the public may react negatively to certain water disposal practices related to water-saturated CBM projects, even though these water disposal practices are regulated to ensure public safety and water conservation. Negative public perception around water-saturated CBM production could impede our access to the resource;
- CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area; and
- regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

Without reserve additions, our reserves and production will decline over time and we require capital to produce remaining reserves.

Our future crude oil and natural gas reserves and production, and therefore our future operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserves and acquiring or discovering additional reserves in the future. Without reserve additions through exploration, development or acquisitions, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flow from operations is insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves and production may be reduced.

Discovered oil and natural gas accumulations are generally only produced when they are economically recoverable. As such, oil and gas prices, and capital and operating costs have an impact on whether accumulations will ultimately be produced. As required by SEC rules, our reserves represent the quantities that we expect to economically recover using existing prices and costs held constant. Reserves can increase or decrease under different price and cost scenarios.

Our reserves include undeveloped properties that require additional capital to bring them on stream.

Proved and probable oil and gas reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

Our oil sands projects face additional risks compared to conventional oil and gas production.

Our Long Lake oil sands development is a fully integrated production, upgrading and cogeneration facility. We are using SAGD technology to recover bitumen from oil sands. The bitumen is partially upgraded using our proprietary OrCrude™ process, followed by conventional hydrocracking to produce sweet, light, PSC™ oil. The OrCrude™ process also yields liquid asphaltenes that are gasified into synthetic gas. This gas is used as fuel for the SAGD process and a source of hydrogen in the upgrading process and to generate electricity through a cogeneration facility.

We have a 65% working interest in this project. Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

Risks associated with our Long Lake project include the following:

APPLICATION OF A RELATIVELY NEW SAGD BITUMEN RECOVERY PROCESS

SAGD has been used in western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade; however, application of SAGD to the insitu recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, although commercial SAGD projects have been in operation for several years. None, however, incorporate the advanced integration and technology associated with a combined SAGD and upgrader operation.

Our estimates for performance and recoverable volumes for the Long Lake project are based primarily on our three well-pair SAGD pilot, the initial performance of our first commercial well phase and industry performance from SAGD operations in similar reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our development assumptions included average well-pair productivity of 900 bbls/d of bitumen and a long-term steam-to-oil ratio within a plant capacity of 3.3. While some of our wells have achieved these levels to date, there can be no certainty that these wells will maintain these levels or that our overall SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved for reasons which could be related to one or all of design, facility or reservoir performance, or integration of our facilities, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, reconfigure or construct additional facilities, purchase natural gas for additional steam generation and/or make short-term bitumen purchases. These could have an adverse impact on the future activities and economic return of the Long Lake project.

APPLICATION OF A NEW BITUMEN UPGRADING PROCESS

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude is the first commercial application of this process. Although the commercial upgrader at Long Lake has been operating since January 2009, there is no certainty that it will sustain or achieve the results that are now being seen or forecast for reasons which could be related to multiple factors, some of which may be related to one or all of design, facility performance, or integration of our facilities. As a result, we may be required to reconfigure, redesign or construct additional facilities. If we are unable to continue to upgrade the bitumen for any reason, we may decide to sell the bitumen directly to third parties without upgrading, which would expose us to the following risks:

- the market for bitumen may be limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent, which may cause its price to increase;
- the market price for bitumen is generally lower than for PSC™, reflecting its quality differential;
- the market price for bitumen fluctuates more than the market price for PSC™ ; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from what we have assumed. This would materially decrease expected earnings from the project and the project may not be profitable under these conditions.

INTEGRATION OF A SAGD FACILITY AND AN UPGRADING FACILITY

The combination of a SAGD facility with the new OrCrude™ upgrading facility is a unique, patented combination of equipment. Although this integrated facility is expected to achieve lower operating costs and has demonstrated that the combination of technologies works, the complexity and degree of integration of the facilities creates conditions for interdependent interruptions and limitations to operations impacting ramp-up of the facilities. This requires a number of reconfigurations and modifications during the initial stages of operation to achieve the reliability, durability and efficiency of operation initially contemplated by its design. There is no certainty that any such changes will successfully resolve the problems we have experienced to date or may experience in the future, which would expose us to additional costs, and associated downtime of one or both of the SAGD production and upgrader facilities, and the potential for increased maintenance requirements.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake project.

DEPENDENCE UPON PROPRIETARY TECHNOLOGY

The success of the Long Lake project and our investment depends highly on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licenced for the project. OPTI and Nexen rely on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licences and patents, to secure the rights to utilize OPTI's proprietary technology and the proprietary technology of third parties. OPTI and Nexen may have to engage in litigation to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of patents or proprietary rights of third parties. Litigation can be time-consuming and expensive, whether successful or not. The process of seeking patent protection can itself be long and expensive. There is no assurance that any pending or future patent applications of OPTI or such third parties will actually result in issued patents or that, if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Others may develop technologies that are similar or superior to: i) the technology of OPTI or third parties; or ii) the design around the patents owned by OPTI and/or third parties.

OPERATIONAL HAZARDS

The operation of the project is subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gas leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions, and our insurance may not sufficiently cover casualty occurrences or disruptions that occur. The Long Lake project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Long Lake project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading it into synthetic crude oil and other products involve particular risks and uncertainties. The Long Lake project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher-value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and, in some situations, result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, per unit operating costs depend largely on production levels.

The Long Lake project is designed to process large volumes of hydrocarbons at high-pressure and temperatures and also handles large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake facilities produce sour gas, which is gas containing hydrogen sulphide and carbon monoxide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. Carbon monoxide is a colourless, odorless and tasteless gas that is toxic at relatively low levels to humans and animals. The project includes integrated facilities for handling and treating the sour gas and for consuming the carbon monoxide as a fuel, including the use of gas-sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shutdown of operations.

The Long Lake project produces carbon dioxide emissions. Risk factors relating to environmental regulation are provided separately in this document.

Aboriginal Claims.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, the Province of British Columbia, and certain governmental entities. They are claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, Alberta and Fort Nelson, British Columbia, including

the lands on which our shale gas and bitumen interests, and those of most other oil sands and shale gas operators in Alberta and British Columbia, are located. As a result, Aboriginal consultation on surface activities is required and may result in timing uncertainties or delays of future development activities. Such claims, if successful, could have a significant adverse effect on our bitumen and shale gas developments.

Some of our production is concentrated in a few producing assets.

A significant portion of our current and future production is generated from highly productive individual wells or central production facilities. Examples include:

- Buzzard, Scott and Ettrick production facilities in the UK North Sea;
- central processing facilities, oil pipelines and an export terminal at our Yemen operations;
- our Long Lake synthetic crude oil operation in the Athabasca oil sands; and
- upgrading facilities at Syncrude in the Athabasca oil sands.

As significant production is generated from each asset, any single event that interrupts one of these operations could result in the loss of production.

Competitive forces may limit our access to natural resources and create labour and equipment shortages.

The oil and gas industry is highly competitive, particularly in the following areas:

- gaining access to areas or countries known to have available resources;
- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include national oil companies, major integrated oil and gas companies and various other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. Key success factors in each of these markets are price, product quality, logistics and reliability of supply.

Competitive forces may result in shortages of: i) prospects to drill; ii) labour; iii) drilling rigs and other equipment to carry out exploration, development or operating activities; and iv) shortages of infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could negatively impact our costs and prices and, therefore, our financial results.

We operate in harsh and unpredictable climates and locations where our access is regulated, which could adversely impact our operations.

Some of our facilities are located in harsh and unpredictable climates and locations that can experience extreme weather conditions and natural disasters, such as sustained ambient temperatures above 40°C or below -35°C, flooding, droughts, wind and dust storms, difficult terrain, high seas, monsoons and hurricanes. These conditions are difficult to anticipate and cannot be controlled. In these conditions, operations can become difficult or unsafe and are often suspended. Some of our facilities and those that our facilities rely upon (such as pipelines, power, communications and oil field equipment) are vulnerable to these types of extreme weather conditions and may suffer extensive damage as a result. If any such extreme weather were to occur, our ability to operate certain facilities and proceed with exploration or development programs could be seriously or completely impaired or destroyed and could have a material adverse effect on our business, financial condition and results of operations. The insurance we maintain may not be adequate to cover our losses resulting from disasters or other business interruptions.

In some areas of the world, access and operations can only be conducted during limited times of the year due to weather or government regulation. These adverse conditions can limit our ability to operate in those areas and can intensify competition during periods of good weather for oil field equipment, services and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs and could have a material adverse effect on our business, financial condition and results of operations. Changing weather patterns may increase the frequency, intensity or duration of these weather conditions and accordingly exacerbate their impacts on our operations.

We operate in countries with political, economic and security risks.

We operate in numerous countries, some of which may be considered politically and economically unstable. A portion of our revenue is derived from operations in these countries. As a result, our financial condition and operating results could be significantly affected by risks associated with international activities, including:

- civil unrest and general strikes;
- political instability, the risk of war and acts of terrorism;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- expropriation or forced renegotiation or modification of existing contracts;
- exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where we currently operate; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

The impact that future potential terrorist attacks or regional hostilities may have on the oil and gas industry, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

We may be affected by changes in government rules and regulations.

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection (as discussed above), marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment that are subject to change from time to time. Current legislation is generally a matter of public record and we cannot predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. Changes in government laws and regulations could adversely affect our results of operations and financial condition.

Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our marketing operations expose us to the risk of financial losses from various sources, which may have a material adverse effect on our financial performance. Our energy marketing team maintains a portfolio comprised of long and short physical and financial positions, which may be significant in size or number at any time. This portfolio of positions is managed based on a trading thesis for expected future pricing levels and trends in forward or regional markets. Unanticipated volatility in commodity price levels and trends upon which those positions are based may cause a position to decrease in value. The transportation and storage assets and contracts undertaken by our energy marketing business may decrease in value due to changes in temporal and regional commodity pricing.

Significant changes in commodity and financial markets could require us to provide additional liquidity if additional collateral is required to be placed with counterparties. We may also be required to reduce some of our energy marketing activities. Adverse credit-related events such as a downgrade of our credit rating to non-investment grade could require additional collateral to be placed with counterparties. Adverse, broad-based, industry credit-related events could also negatively affect trading counterparties who fail to fulfill their contractual obligations.

Use of marine transportation may expose us to the risk of financial loss and damaged reputation.

From time to time, we may choose to charter marine vessels for the transportation of crude oil. This may expose us to the risk of financial loss and damaged reputation in the event of oil spills.

The inability of counterparties and joint operating partners to fulfill their obligations to us could adversely impact our results of operations.

Credit risk arises from the sale of production and products our energy marketing group buys for resale, from financial contracts we acquire for hedging and trading purposes and from our joint venture partners for their share of capital and operating costs where we operate. There is the risk of loss and additional burden for amounts in excess of available remedies if counterparties or joint venture partners do not or cannot fulfill their contractual obligations.

Our debt and other financial commitments may limit our financial and operating flexibility.

As of December 31, 2010 our long-term debt was approximately $5.2 billion. We also have commitments under capital leases, operating leases, drilling rig contracts, transportation and storage contracts, and purchase obligations for services and products. Our debt levels and financial commitments could have significant and adverse consequences to our business, including:

- an increased sensitivity to adverse economic and industry conditions;
- a limited ability to fund future working capital and capital expenditures, engage in future acquisitions or development activities, or to otherwise fully realize the value of assets or opportunities because a substantial portion of our cash flows are required to service debt and other obligations;
- a limited ability to plan for, or react to, industry trends; and
- an uncompetitive position relative to our competitors whose debt and financial commitment levels are lower.

A downgrade in our credit rating could increase our cost of capital and limit access to capital.

Rating agencies regularly evaluate the company and our subsidiaries, and their ratings of our long-term and short-term debt are based on a number of factors. This includes our financial strength as well as factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the wider state of the economy. We cannot be assured that one or more of our credit ratings will not be downgraded. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. In addition, credit ratings may be important to customers or counterparties when we compete in certain markets and when we seek to engage in certain transactions including transactions involving over-the-counter derivatives.

It is our objective to maintain high quality credit ratings appropriate for our business activities. A credit-rating downgrade could potentially limit our access to private and public credit markets and increase the costs of borrowing under existing facilities. A reduction in our credit ratings also could have a significant impact on certain trading revenues, particularly in those businesses where counterparty creditworthiness is critical. It could trigger collateralization requirements related to physical and financial derivative liabilities with certain marketing counterparties and facility construction contracts. The occurrence of any of the foregoing could adversely affect our ability to execute portions of our business strategy and could have a material adverse effect on our liquidity and capital position.

In connection with certain over-the-counter derivatives contracts and other trading agreements, we could be required to provide additional collateral or to terminate transactions with certain counterparties in the event of a downgrade of our credit ratings. The amount of additional collateral required depends on the contract and is usually a fixed incremental amount and/or the market value of the exposure.

CAPITAL STRUCTURE

Authorized Capital

Our authorized capital consists of an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares without nominal or par value, issuable in series. As at December 31, 2010, 525,706,403 common shares were issued and outstanding. No preferred shares were issued.

Common Shares

Each common share entitles the holder to receive notice of, attend and one vote at all meetings of our shareholders, other than meetings at which only the holders of a specified class or series of shares are entitled to vote. The holders of common shares are entitled, subject to the rights, privileges, restrictions and conditions attached to other classes of shares of Nexen, to receive any common share dividend declared by the board and to receive the remaining property of Nexen upon dissolution of the company. There are no pre-emptive or conversion rights attached to the common shares and the common shares are not subject to redemption. All common shares currently outstanding, and potentially outstanding upon the exercise of outstanding options, are, or will be, fully paid and non-assessable.

Preferred Shares

Preferred shares may be issued in one or more series. Each series consists of such number of shares and with the designation, rights, restrictions, conditions and limitations as determined by our board of directors.

Holders of preferred shares are not entitled to receive notice of, attend or vote at our shareholder meetings, unless payments of four quarterly preferred share dividends of any series remain outstanding and unpaid. As long as any preferred share dividend of any series remains in arrears, the holders of preferred shares are entitled to receive notice of and to attend all meetings of our shareholders and are entitled to one vote in respect of each preferred share held. In these circumstances, holders of preferred shares will be entitled, voting separately and exclusively as a class, to elect two directors to our board.

Issued preferred shares will have priority over the common shares in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding-up of Nexen. Each series of preferred shares rank in parity with preferred shares of every other series with respect to priority in payment of dividends and in the distribution of assets.

Shareholder Rights Plan

A shareholder rights plan (the Plan) exists for holders of common shares of Nexen. The Plan creates a right for each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. Prior to the separation date, the rights are not separable from the common shares and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our board can defer the separation date. The Plan must be reapproved by shareholders on or before our annual general meeting in 2011 to remain effective past that date. A copy of the Plan is available on our website at www.nexeninc.com.

Credit Ratings

The following information relating to our credit ratings is provided as it relates to Nexen's financing costs, liquidity and operations. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. Additionally, our ability to engage in certain collateralized business activities on a cost effective basis depends on Nexen's credit ratings. A reduction in the current rating on our debt by rating agencies, particularly a downgrade below current ratings, or a negative change in the ratings outlook could adversely affect our cost of financing and our future access to sources of liquidity and capital. In addition, changes in credit ratings may affect our ability to, and the associated costs of: i) entering into ordinary course derivative or hedging transactions and may require posting additional collateral under certain contracts; and ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

The table below details our current credit ratings and outlooks for our senior unsecured debt issued by credit rating agencies as of December 31, 2010. A credit rating is an independent measure intended to give an indication of a company's ability to meet its financial commitments under the rated securities. Ratings are not recommendations to buy, hold or sell the debt and may be subject to revisions or withdrawal at any time by the rating agency. We believe our financial results, ample liquidity and financial flexibility continue to support our credit ratings.

	Standard & Poor's Rating Service (S&P)	Moody's Investors Services (Moody's)	DBRS Limited (DBRS)
Senior Unsecured/Long-Term Rating	BBB-	Baa3 (under review)	BBB
Outlook	Stable	Stable	Stable

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. According to S&P's rating system, an obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. Debt securities rated 'BBB-' are at the lowest end of these investment grade securities.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, representing the range from highest to lowest quality of such securities rated. Moody's applies numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa in its long-term debt rating system. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of that generic rating category. According to the Moody's rating system, debt securities rated 'Baa3' are subject to moderate credit risk, considered medium grade and may possess certain speculative characteristics. In early December 2010, Moody's placed our rating under review, primarily as a result of the delayed ramp up of Long Lake and higher absolute amounts of debt before considering our cash on hand. Discussions with Moody's are ongoing and the outcome is indeterminable at this time.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such securities rated. Each rating category between AA and C can be modified by the designations "high" and "low", which indicate the relative standing of a rating within a particular rating category. The absence of either a "high" or "low" designation indicates that the rating is in the "middle" of the category. According to DBRS' rating system, long-term debt securities rated 'BBB' are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, however, it may be vulnerable to future events.

Risks and uncertainties related to our credit ratings and their possible impacts are discussed more fully in the section titled "Risk Factors" under the section titled "A downgrade in our credit rating could increase our cost of capital and limit access to capital".

Quarterly Dividends Declared on Common Share

(Cdn$/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010	0.050	0.050	0.050	0.050
2009	0.050	0.050	0.050	0.050
2008	0.025	0.050	0.050	0.050

Subject to applicable law, our board of directors determines if and when dividends are declared on our common shares. Historically, dividends have been declared quarterly and paid on the first business day of the subsequent quarter. All dividends paid to holders of common shares in 2010 have been designated as "eligible dividends" for Canadian tax purposes. This designation will apply to all such dividends paid in the future unless otherwise notified by us.

The Income Tax Act (Canada) requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

MARKET FOR SECURITIES

Common Shares

Our outstanding common shares are listed and traded on the TSX and NYSE under the trading symbol "NXY". The following table provides the market price ranges and the aggregate volume of trading of the common shares on the TSX and NYSE for the periods indicated:

	Toronto Stock Exchange *Cdn$*				New York Stock Exchange *US$*			
2010	**High**	**Low**	**Close**	**Volume**	**High**	**Low**	**Close**	**Volume**
January	25.91	22.38	23.41	29,143,776	24.93	21.06	21.94	48,404,421
February	24.57	22.69	23.75	35,115,190	23.25	21.31	22.50	48,939,602
March	25.34	23.45	25.13	31,832,701	24.98	22.61	24.71	31,293,552
April	26.91	24.26	24.70	39,503,585	26.92	23.96	24.28	41,802,292
May	24.89	21.58	23.50	41,360,427	24.60	20.00	21.81	61,794,873
June	23.60	20.92	20.94	33,436,024	22.77	19.66	19.67	36,653,095
July	22.33	20.34	21.35	31,422,187	21.54	19.19	20.70	33,944,207
August	21.89	18.33	19.75	42,714,266	21.45	17.20	18.51	29,970,477
September	21.03	19.31	20.70	37,048,759	20.48	18.69	20.10	38,727,967
October	22.74	20.57	21.70	37,331,540	22.39	20.12	21.29	48,129,155
November	22.71	20.68	21.47	35,243,469	22.56	20.42	20.92	49,103,219
December	23.00	21.11	22.80	28,466,298	23.01	20.73	22.90	39,177,560

Subordinated Notes

Our 7.35% subordinated notes due 2043 (7.35% Notes) are listed and traded on the TSX under the trading symbol "NXY.PRU" and on the NYSE under the trading symbol "NXYPRB". The following table provides the market price ranges and the aggregate volume of trading of the 7.35% Notes on the TSX and NYSE for the periods indicated:

	Toronto Stock Exchange Cdn$				New York Stock Exchange US$			
2010	**High**	**Low**	**Close**	**Volume**	**High**	**Low**	**Close**	**Volume**
January	24.46	24.19	24.25	113,146	25.07	23.60	24.23	324,085
February	23.99	23.94	23.97	29,946	24.60	23.57	23.95	364,104
March	24.85	24.77	24.83	26,103	25.08	24.38	24.82	231,756
April	25.01	24.93	24.97	76,910	25.08	24.50	24.85	158,619
May	24.65	24.51	24.60	29,850	24.93	23.76	24.54	136,145
June	24.76	24.66	24.69	22,164	24.90	24.26	24.63	436,078
July	24.95	24.91	24.94	13,414	25.23	24.55	24.89	447,731
August	25.03	24.96	24.98	13,982	25.18	24.80	24.99	207,052
September	25.29	25.20	25.24	8,655	25.50	25.00	25.21	144,803
October	25.35	25.23	25.33	19,215	25.50	24.89	25.21	117,458
November	25.29	25.19	25.24	33,026	25.31	25.05	25.20	108,412
December	25.24	25.17	25.21	23,196	25.24	25.09	25.17	183,722

Prior Sales

For information in respect of share issuances related to the exercise of stock options and our dividend reinvestment plan, see Note 14 to our annual Consolidated Financial Statements for the year ended December 31, 2010, which are incorporated by reference into this AIF.

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On February 11, 2009, the board set the size at 12 directors effective April 28, 2009.

Our By-Laws provide that directors will be elected at the annual general meeting (AGM) each year and will hold office until the following AGM when their successors are elected.

Name (Age)	**Residence**	**Principal Occupation**[1]	**Other Directorships**	**Nexen Director Since**
William B. Berry[3] (58)	Houston, Texas, United States	Retired oil executive Formerly: Executive Vice President of ConocoPhillips	Willbros Group, Inc.	2008
Robert G. Bertram[3] (66)	Aurora, Ontario, Canada	Retired pension investment executive Formerly: Executive Vice President of Ontario Teachers' Pension Plan Board	Mulvihill Capital Management Funds[2] The Cadillac Fairview Corporation Maple Leaf Sports and Entertainment Ltd.	2009
Dennis G. Flanagan[3] (71)	Calgary, Alberta, Canada	Retired oil executive	Canexus Income Fund (Chair)	2000
S. Barry Jackson (58)	Calgary, Alberta, Canada	Retired oil executive Formerly: Chair of Resolute Energy Inc. and Chair of Deer Creek Energy Limited	TransCanada Corporation (Chair) TransCanada PipeLines Limited (Chair) WestJet Airlines Ltd.	2001
Kevin J. Jenkins[3] (54)	Windsor, Berkshire, United Kingdom	President and Chief Executive Officer of World Vision International Formerly: Managing Director of TriWest Capital Partners	–	1996
A. Anne McLellan, P.C., O.C. (60)	Edmonton, Alberta, Canada	Counsel with Bennett Jones LLP, Barristers and Solicitors, and Distinguished Scholar in Residence at the University of Alberta in the Institute for United States Policy Studies Formerly: Member of Parliament for Edmonton Centre, Deputy Prime Minister, Minister of Public Safety and Emergency Preparedness and Minister of Health	Agrium Inc. Cameco Corporation	2006
Eric P. Newell, O.C. (66)	Edmonton, Alberta, Canada	Retired oil executive	–	2004
Thomas C. O'Neill[3] (65)	Toronto, Ontario, Canada	Retired chartered accountant	Adecco S.A. (Vice Chair) BCE Inc. (Chair) Loblaw Companies Limited The Bank of Nova Scotia	2002
Marvin F. Romanow (55)	Calgary, Alberta, Canada	President and CEO of Nexen Formerly: Executive Vice President and CFO of Nexen	–	2009
Francis M. Saville, Q.C. (72)	Calgary, Alberta, Canada	Chair of Nexen Formerly: Counsel with Fraser Milner Casgrain LLP, Barristers and Solicitors	–	1994
John M. Willson (71)	Vancouver, British Columbia, Canada	Retired mining executive	–	1996
Victor J. Zaleschuk[4] (67)	Calgary, Alberta, Canada	Retired oil executive	Agrium Inc. Cameco Corporation (Chair)	1997

1 *Current and within the past five years.*
2 *An investment management fund organization managing a series of closed-end funds listed on the TSX. Mr. Bertram is an Audit Committee member for each of these funds.*
3 *Financial experts on Nexen's Audit Committee.*
4 *Mr. Zaleschuk was President and CEO of Nexen from 1997 to 2001.*

Previous Directorships

The following table details the previous directorships held by our directors over the last five years at public and registered investment companies.

Name	Company
Flanagan	NAL Oil and Gas Trust
Jackson	Cordero Energy Inc., Resolute Energy Inc., Deer Creek Energy Limited
Newell	Canfor Corporation
O'Neill	Dofasco Inc., Ontario Teachers' Pension Plan Board
Romanow	Canexus Income Fund
Saville	Mullen Transport Inc.
Willson	Finning International Inc., Pan American Silver Corp., Harry Winston Diamond Corp.

Conflicts of Interest

As described on page 55, certain of Nexen's directors are associated with other issuers engaged in the oil and gas industry and the interests of these directors could come into conflict with the interests they hold in these other issuers. In the event of a conflict of interest, Canadian legislation requires the director to disclose to Nexen the nature and extent of any interest they have in a material contract or material transaction, if the director is a party to the contract or transaction in question, if the director is a director or an officer of a party to the contract or transaction in question or has a material interest in a party to the contract or transaction. Nexen's Integrity Guide also sets forth a detailed process for dealing with conflicts of interest.

Board Committees

	Committees (Number of Members)					
	Audit[1, 2] (6)	**Compensation**[1] (7)	**Governance**[1] (7)	**Finance**[1] (7)	**HSE & SR**[1] (7)	**Reserves**[1] (7)
Management Director—Not Independent						
Marvin F. Romanow						
Independent Outside Directors						
William B. Berry[3]	√	√			√	Chair
Robert G. Bertram[3, 4]	√		√	√		
Dennis G. Flanagan[3]	√			√	√	√
S. Barry Jackson		√	Chair	√		√
Kevin J. Jenkins[3]	√	Chair	√	√		
A. Anne McLellan, P.C., O.C.		√	√	√	√	
Eric P. Newell, O.C.	√		√		Chair	√
Thomas C. O'Neill[3, 5, 6]	Chair	√	√			√
Francis M. Saville, Q.C.		√	√	√	√	
John M. Willson		√			√	√
Victor J. Zaleschuk				Chair	√	√

1 *All members are independent. All Audit Committee members are independent and financially literate under additional regulatory requirements applicable to them.*
2 *Experience of the members of the Audit Committee that indicates an understanding of the accounting principles we use to prepare our financial statements is shown on page 57.*
3 *Audit Committee financial expert under US regulatory requirements.*
4 *Mr. Bertram is a board member and participates in the audit committee function for six exchange-listed funds. The funds are related managed entities and limited in business purpose as investment funds. They are restricted to a mandate of a limited number of specific securities and dealt with as a group, making preparation and review time significantly less than would be associated with a single full-operating business. The board has considered and determined that Mr. Bertram's participation in these funds does not impede his ability to fully carry out his duties as a Nexen director and committee member.*
5 *The board determined that Mr. O'Neill's service on the audit committees of three other public companies does not impair his ability to serve as Chair of Nexen's Audit Committee. The board considered that Mr. O'Neill has over 30 years of experience as a chartered accountant and, since retiring as Chair of PwC Consulting in 2002, his only business commitments are to the boards and committees on which he serves.*
6 *The board extended Mr. O'Neill's Audit Committee Chair term to provide continuity in leadership in light of recent changes to committee membership and IFRS conversion.*

AUDIT COMMITTEE INFORMATION

Each member of the Audit Committee has a thorough understanding of accounting principles and has the ability to assess the application of accounting principles in connection with the preparation of financial statements and the accounting for estimates, accruals and reserves. Audit Committee members have an understanding of internal controls and procedures and have experience preparing, auditing, analyzing or evaluating financial statements or supervising individuals engaged in those roles. Each Audit Committee member's education and experience is described below.

Audit Committee Education and Experience

Name	Experience
Berry	William Berry is a retired oil and gas executive. He was formerly Executive Vice President of ConocoPhillips from 2003 to 2008. He also held other senior executive positions with Phillips Petroleum Co., including Senior Vice President, Exploration and Production. His career in the oil and gas industry began in 1976 and includes experience working in Africa, the North Sea, Asia, Russia, the Caspian Sea and North America. Mr. Berry has Bachelor and Masters of Science degrees in Petroleum Engineering from Mississippi State University. He was responsible for understanding the financial reporting of exploration and production at ConocoPhillips and had finance managers reporting directly to him on a functional basis. He held various management roles, including Manager, Corporate Planning and Budgeting.
Bertram	Robert Bertram is a retired pension investment executive. He was the Executive Vice President of Ontario Teachers' Pension Plan Board (Teachers) from 1990 to 2008. He led Teachers' investment program and had oversight of the pension fund's growth to $108.5 billion from $19 billion when it was established in 1990. Prior to that, he spent 18 years at Telus Corporation, formerly Alberta Government Telephones, where his responsibilities included investment management, the capital procurement program, corporate risk management, tax and compliance. Before leaving Telus, he was Assistant Vice President and Treasurer. Mr. Bertram has a Bachelor of Arts degree in History from the University of Calgary and a Master of Business Administration from the University of Alberta. He is a Chartered Financial Analyst (CFA) charter holder.
Flanagan	Dennis Flanagan is a retired oil and gas executive. He worked in the oil and gas industry for more than 40 years with Ranger Oil Limited (Ranger) and ELAN Energy Inc. (ELAN), most recently as Executive Chair of ELAN until it was bought by Ranger in 1997. He was involved in all phases of exploration and development in Canada, the US and the UK North Sea. Mr. Flanagan completed the Registered Industrial and Cost Accountant program, the predecessor to the Certified Management Accountant program, in 1967. He worked in various accounting and management positions at Ranger, including as the Chief Financial Officer (CFO) and Executive Vice President.
Jenkins	Kevin Jenkins is President and Chief Executive Officer of World Vision International. He was formerly a Managing Director of TriWest Capital Partners, an independent private equity firm, from 2003 to 2009. He was President, CEO and a director of The Westaim Corporation from 1996 to 2003. From 1985 to 1996, he held senior executive positions with Canadian Airlines International Ltd. (Canadian). Mr. Jenkins was elected to Canadian's Board of Directors in 1987, appointed President in 1991 and appointed President and CEO in 1994. Earlier in his career he was CFO of Canadian. Mr. Jenkins has a Bachelor's Degree in Law from the University of Alberta and a Masters of Business Administration from Harvard Business School. He has worked in management positions with increasing levels of responsibility, including Assistant Treasurer, Vice President Finance, Executive Vice President and Chief Financial Officer, and President and CEO.
Newell	Eric Newell is the retired Chancellor of the University of Alberta, a position he held from 2004 to 2008. He is the retired Chair and CEO of Syncrude Canada Ltd. (Syncrude), positions he held from 1994 and 1989, respectively, until 2004. He served as President of Syncrude from 1989 to 1997. Prior to that, he was Vice President Finance and Administration. With over 14 years experience as CEO, Dr. Newell has had CFO's, Controllers and various finance managers report directly to him on a functional basis. Dr. Newell holds a Bachelor of Applied Science degree in Chemical Engineering from the University of British Columbia and a Masters of Science in Management Studies from the University of Birmingham, England.
O'Neill	Tom O'Neill is the retired Chair of PwC Consulting. He was formerly CEO of PwC Consulting; COO of PricewaterhouseCoopers LLP, Global; CEO of PricewaterhouseCoopers LLP, Canada and Chair and CEO of Price Waterhouse Canada. He worked in Brussels in 1975 to broaden his international experience and from 1975 to 1985 was lead partner for numerous multinational companies, specializing in dual Canadian and US listed companies. Mr. O'Neill has a Bachelor of Commerce Degree from Queen's University. He received his Chartered Accountant designation in 1970 and was made a Fellow (FCA) of the Institute of Chartered Accountants of Ontario in 1988. Mr. O'Neill lectured on Political Economics at the University of Toronto, taught courses in commerce and finance, and has been actively involved in a number of associations, including various committees of the Canadian and Ontario Institutes of Chartered Accountants.

The Audit Committee mandate is included in Appendix A, on page 63 of this AIF.

All Committee mandates, including those for the Audit, Compensation and Governance Committees, our code of ethics and our corporate governance policy and categorical standards are available at www.nexeninc.com. Shareholders wishing to receive a copy of these documents may contact the Governance Office by telephone at 403.699.4926, or by email at governance@nexeninc.com.

INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS (IRCA) FEES

Pre-Approval Policies and Procedures

Nexen has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non–audit services to be provided by the IRCA. The Audit Committee approves the services and the related fees. The services are sufficiently detailed to ensure that: i) the Audit Committee understands the services it is being asked to pre–approve; and ii) Nexen's management does not need to make a judgement as to whether a proposed service fits within the pre–approved services.

IRCA services that arise that were not pre-approved by the Audit Committee must be pre–approved by the Audit Committee chair. The Audit Committee is informed of the services at its next meeting.

Nexen did not rely on the de minimus exemption provided by Section (c)(7)(i)(C) of Rule 2–01 of SEC Regulation S–X in either 2009 or 2010.

IRCA Fees Billed

The following table provides information about the fees billed to Nexen for professional services rendered by the IRCA during 2010 and 2009.

Type of Fee	Billed in 2009	Billed in 2010	Percentage of Total Fees Billed in 2010
Audit Fees[1]	3,591,321	3,252,415	63%
Audit-Related Fees[2]	1,786,308	1,727,203	33%
Tax Fees[3]	151,269	59,251	1%
All Other Fees[4]	262,848	163,975	3%
Total Annual Fees	**5,791,746**	**5,202,844**	**100%**

1 *Audit fees were paid to the IRCA for the audit of Nexen's and Canexus' annual financial statements or services provided in connection with statutory and regulatory filings or engagements.*

2 *Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of subsidiary financial statements and are not reported as Audit Fees.*

3 *Tax fees were paid to the IRCA for tax compliance services and tax-related consultation.*

4 *Other fees were paid to the IRCA for subscriptions to auditor-provided and supported tools.*

EXECUTIVE OFFICERS

The board determines the term of office for each executive officer. Below are Nexen's executive officers, including prior offices and non-executive positions for each of them during the past five years. Start dates with Nexen are indicated for officer positions.

Officer *(Age)*	Residence	Current and Past Position(s)	Effective Date of Current Position	Executive Officer Since
Marvin F. Romanow (55)	Calgary, Alberta, Canada	President and CEO and a director. Formerly: Executive VP and CFO since June 1, 2001.	January 1, 2009	1997
Kevin J. Reinhart (52)	Calgary, Alberta, Canada	Executive VP and CFO. Formerly: Senior VP and CFO since January 1, 2009; Senior VP, Corporate Planning and Business Development since November 1, 2007; VP, Corporate Planning and Business Development since July 11, 2002.	April 27, 2010	1994
Matthew J. Fox (50)	Calgary, Alberta, Canada	Executive VP, International. Formerly: President and CEO at Conoco-Phillips Canada since July 2009; Senior VP, Oil Sands at Conoco-Phillips Canada since 2007; Manager of North Slope Development in Alaska at Conoco-Phillips since 2003.	April 1, 2010	2010
Gary H. Nieuwenburg (52)	Calgary, Alberta, Canada	Executive VP, Canada. Formerly: Senior VP, Synthetic Crude since November 1, 2007; VP, Synthetic Crude since July 11, 2002.	May 1, 2009	2001
James T. Arnold (51)	Calgary, Alberta, Canada	Senior VP, Synthetic Crude. Formerly: Division VP Operations and Projects, Synthetic Oil since February 1, 2009; Chief Operating Officer at OPTI Canada Inc. since October 13, 2005.	July 16, 2009	2009
Eric B. Miller (48)	Calgary, Alberta, Canada	Senior VP, General Counsel and Secretary. Formerly: VP, General Counsel and Secretary since July 11, 2007; Division VP and Chief Legal Counsel since July 1, 2006; Division VP, Legal Canadian Oil and Gas since March 1, 2002.	April 27, 2010	2007
Una M. Power (46)	Calgary, Alberta, Canada	Senior VP, Corporate Planning and Business Development. Formerly: VP, Corporate Planning and Business Development since January 16, 2009; Treasurer since July 11, 2002.	April 27, 2010	1998
Brian C. Reinsborough (49)	Dallas, Texas, United States	Senior VP, United States Oil and Gas. Formerly: Division VP, Exploration, Operations and Production since May 12, 2006; Division VP, Exploration since July 8, 2002.	November 1, 2007	2007
Catherine J. Hughes (48)	Calgary, Alberta, Canada	VP, Operational Services, Technology and Human Resources. Formerly: Division VP, Operational Services, Technology and Human Resources since December 1, 2009; Division VP, Operational Services and Technology since September 1, 2009; VP Oil Sands at Husky Oil Operations Ltd. since October 1, 2007; VP Exploration and Production Services at Husky Oil Operations Ltd. since September 1, 2005.	February 17, 2010	2010
Kim D. McKenzie (62)	Calgary, Alberta, Canada	VP and Chief Information Officer. Formerly: Division VP, Information Technology since January 1, 1992.	November 1, 2007	2007
Kevin J. McLachlan (47)	Calgary, Alberta, Canada	VP, Global Exploration. Formerly: Division VP, Global Exploration since July 1, 2009; Division VP, International Exploration since August 1, 2008; Manager, Exploration, since January 1, 2006; East Coast Exploration Manager at Imperial Oil Resources since April 1, 2005.	February 17, 2010	2010
Brendon T. Muller (42)	Calgary, Alberta, Canada	Controller. Formerly: Manager, Corporate External Reporting since November 1, 2003.	April 9, 2007	2007
J. Michael Backus (40)	Calgary, Alberta, Canada	Treasurer. Formerly: Manager, Planning, Synthetic Crude since January 1, 2009; Project Planner—Phase 2 Long Lake, Synthetic Crude since April 1, 2005.	February 16, 2009	2009

OTHER

Legal Proceedings and Regulatory Actions

Nexen is party to various legal proceedings, both as a claimant and as a defendant, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts awarded to us or assessed against us would not have a material effect on our consolidated financial position or results of operations. In any event, there are no legal proceedings to which we are a party or which our property is the subject of, nor are there any proceedings known by us to be contemplated that involves a claim for damages exceeding 10% of our current assets. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US Environmental Protection Agency, state environmental agencies and certain third parties for certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands and lawsuits have been received for certain sites related to historical operations and activities in the US. Although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

During the year ended December 31, 2010, there have been no; i) penalties or sanctions imposed against Nexen or its subsidiaries by a court relating to securities legislation or by a securities regulatory authority; or ii) settlement agreements entered into by Nexen or its subsidiaries before a court relating to securities legislation or with a securities regulatory authority. There have been no penalties or sanctions imposed by a court or regulatory body relating to any other legislation against Nexen or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision.

Interests of Management and Others in Material Transactions

No director or executive officer of Nexen or its subsidiaries, or any person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of Nexen's outstanding voting securities or any associate or affiliate of these persons currently has, or has had, any material interests in any transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect Nexen or any of Nexen's subsidiaries, within the three most recently completed financial years or during the current financial year.

Shareholdings of Directors and Executive Officers

At December 31, 2010, Nexen's directors and executive officers as a group beneficially own, directly or indirectly, or exercise control or direction over, less than 1% of Nexen's issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As of the date of this AIF, we confirm that, to the best of our knowledge:

(a) in the last 10 years, no director or executive officer of Nexen is or has been a director, chief executive officer or chief financial officer of another company or has owned a personal holding company that:
   - i) was subject to a cease trade order or an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an order) while the director or executive officer was acting as a director, chief executive officer or chief financial officer; or

ii) was subject to an order after the director or executive officer ceased to be a director, chief executive officer or chief financial officer in the company and which resulted from an event that occurred while that person was acting in the capacity as a director, chief executive officer or chief financial officer.

(b) in the last 10 years, no director or executive officer of Nexen has been a director or executive officer of a company that became bankrupt or made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets while the director or executive officer was acting as a director or executive officer of such company or within a year of ceasing to act in that capacity;

(c) no director or executive officer of Nexen nor any personal holding company controlled by such person has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer; and

(d) no director or executive officer of Nexen has been subject to:

i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Transfer Agents and Trustees

In Canada, CIBC Mellon Trust Company is our transfer agent and registrar of the Company's common shares. They are located at:

CIBC Mellon Trust Company
199 Bay Street
Commerce Court West
Securities Level
Toronto, ON M5L 1G9

In the United States, BNY Mellon Shareowner Services is our transfer agent and registrar of the Company's common shares. They are located at:

BNY Mellon Shareowner Services
480 Washington Blvd., 27th Fl.
Jersey City, NJ 07310

Deutsche Bank Trust Company Americas, 60 Wall Street, 27th Floor, Mailstop NYC 60-2710, New York, New York 10005-2858, acts as trustee for the 7.35% Notes listed on the TSX and NYSE.

Material Contracts

During the year ended December 31, 2010, Nexen did not enter into any material contracts, and there are no material contracts still in effect, other than contracts entered into in the ordinary course of business.

Interest of Experts

Deloitte & Touche LLP is our registered chartered accountant and has advised Nexen's Audit Committee that they are independent with respect to Nexen within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules and standards of the U.S. Public Company Accounting Oversight Board and the securities laws and regulations administered by the SEC.

Information related to reserves in this AIF was reviewed by McDaniel & Associates Consultants Ltd., Ryder Scott Company LP and DeGolyer and MacNaughton, each of which is an independent qualified reserves evaluator.

As of the date hereof, none of the partners, principals, employees or consultants of McDaniel & Associates Consultants Ltd., Ryder Scott Company LP or DeGolyer and MacNaughton, through registered or beneficial interests, directly or indirectly, held, or are entitled to receive more than 1% of any class of Nexen's outstanding securities, including the securities of our associates and affiliates.

The information relating to the Company's NI 51-101 reserves as at December 31, 2010 incorporated by reference in this AIF has been compiled by the Company based on the report dated February 16, 2011 prepared by Mr. Ian R. McDonald, an employee of Nexen, in his capacity as the Company's Internal Qualified Reserves Evaluator. Mr. McDonald beneficially owns, directly or indirectly, less than 1% of any class of the Company's securities.

Additional Information

Nexen is a Canadian issuer that is registered with both the Canadian securities commissions and the SEC and trades on both the TSX and NYSE. Additional information relating to the Company can be found on the SEDAR website at www.sedar.com and on EDGAR at www.sec.gov.

Additional information including directors' and officers' remuneration and indebtedness, director nominees standing for re-election, principal holders of the Company's securities, and securities authorised for issuance under the Company's equity compensation plans, is contained in the Company's Proxy Circular for the 2011 Annual General Meeting of Shareholders.

Additional financial information is provided in our MD&A and Consolidated Financial Statements for the most recently completed financial year.

Copies of our annual report may be obtained free of charge from Nexen's website at www.nexeninc.com or upon request from:

Investor Relations
Nexen Inc.
701 8th Avenue S.W.
Calgary, Alberta T2P 3P7
(403) 699-5454

Information located on or accessible through Nexen's website does not form part of this AIF and is not incorporated by reference herein, unless specifically otherwise stated.

APPENDIX A—AUDIT AND CONDUCT REVIEW COMMITTEE MANDATE

Audit and Conduct Review Committee Mandate

The Audit and Conduct Review Committee (Committee) of the Board of Directors (Board) of Nexen Inc. (Nexen) has the oversight responsibility and specific duties described below.

COMPOSITION

The Committee will be comprised of at least three directors. All Committee members will be independent under the Categorical Standards for Director Independence (Categorical Standards) adopted by the Board and applicable law. Any Committee member who, for any reason, is no longer independent under the Categorical Standards or applicable law immediately ceases to be a Committee member.

All Committee members will be "financially literate" under the definition adopted by the Board. At least one Committee member shall be designated as an "audit committee financial expert" under applicable law.

Committee members may not serve on the audit committees of more than two additional public companies without the approval of the Board.

Committee members will be appointed and removed by the Board. The Committee Chair will be appointed by the Board.

RESPONSIBILITY

The Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to i) the integrity of annual and quarterly financial statements to be provided to shareholders and regulatory bodies; ii) compliance with accounting and finance based legal and regulatory requirements; iii) the independent auditor's qualifications and independence; iv) the system of internal accounting and financial reporting controls that Management has established; v) performance of the internal and external audit process and of the independent auditor; and, vi) implementation and effectiveness of How We Work: Our Integrity Guide (Our Integrity Guide), which constitutes our code of ethics and the compliance programs.

SPECIFIC DUTIES

The Committee will:

Audit and Conduct Review Leadership

1. Have a clear understanding with the independent auditor that it must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the independent auditor is to the Committee, as representatives of the shareholders.
2. Provide an avenue for communication between each of internal audit (Corporate Audit), the independent auditor, financial and senior Management and the Board.
3. Review and, in the Committee's discretion, approve and recommend to the Board for consideration Our Integrity Guide, including procedures for i) the receipt, retention, and treatment of complaints received by Nexen regarding accounting, internal accounting and financial reporting controls, or auditing matters; ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and, iii) addressing a reporting attorney's report of a material breach of securities law, material breach of fiduciary duty or similar material violation.
4. Take all reasonable steps to oversee the implementation of Our Integrity Guide, including reviewing with Management Our Integrity Guide and the implementation and effectiveness of compliance programs under Our Integrity Guide.
5. Take all reasonable steps to oversee conduct review by receiving an annual report summarizing the statements of compliance completed by employees pursuant to the Integrity Program, the Conflict of Interest Policy and the Prevention of Improper Payments Policy and make any resulting inquiries the Committee decides is needed.
6. With the Board and the Board Chair, respond to potential conflict of interest situations.

Independent Auditor Qualifications and Selection

7. Subject to required shareholder approval of auditors, be solely responsible for selecting, retaining, compensating, overseeing and, where necessary, terminating the independent auditor. The independent auditor will be a "Registered Public Accounting Firm" and a "Participating Audit Firm", each as defined under applicable law and will report directly to the Committee. The Committee is entitled to adequate funding from Nexen to compensate the independent auditor for completing an audit and audit report or performing other audit, review or attest services.
8. Evaluate the independent auditor's qualifications, performance and independence. As part of that evaluation, at least annually review a report by the independent auditor describing: the firm's (auditor's) internal quality control systems and procedures; any material issues, defects, restrictions or sanctions raised or imposed by the most recent internal quality control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities or board, within the preceding five years, respecting one or more independent audits carried out by the firm or otherwise arising, and any steps taken to deal with any such issues, defects, restrictions or sanctions; and, (to assess the auditor's independence) all relationships between the independent auditor and Nexen. Take all reasonable steps to satisfy itself that the independent auditor does not provide non-audit services that would disqualify it as independent under applicable law.
9. Review the experience and qualifications of the senior members of the independent audit team and the quality control procedures of the independent auditor. Take all reasonable steps to satisfy itself that the lead audit partner of the independent auditor is replaced periodically, according to applicable law. Take all reasonable steps to satisfy itself of the continuing independence of the independent audit firm. Present the Committee's conclusions on auditor independence to the Board.
10. Recommend guidelines for Nexen's hiring of partners and employees and former partners and employees of the current and any former independent auditor who were engaged on Nexen's account to the Board for consideration.

Independent Audit Process

11. Pre-approve all audit services (which may include comfort letters in connection with securities underwritings). In the discretion of the Committee, annually delegate to the Committee Chair the authority to grant pre-approvals for certain audit services to expedite the hiring of the independent auditor for minor, time-sensitive audit services provided that those pre-approvals are presented in writing to the Committee at the next regularly scheduled meeting. The Committee Chair's pre-approval authority is limited to audit services required to start before the next regularly scheduled Committee meeting. The Committee Chair will not pre-approve audit services related to Nexen's integrated audit.
12. Pre-approve and disclose, as required, the retention of the independent auditor for non-audit services permitted under applicable law. In the discretion of the Committee, annually delegate to one or more of its members the authority to grant pre-approvals for non-audit services provided that those pre-approvals are presented in writing to the Committee at the next regularly scheduled meeting.
13. Meet with the independent auditor prior to the audit to review the scope and general extent of the independent auditor's annual audit including i) the planning and staffing of the audit; and, ii) an explanation from the independent auditor of the factors considered in determining the audit scope, including the major risk factors.

14. Require the independent auditor to provide a timely report setting out i) all critical accounting policies, significant accounting judgments and practices to be used; ii) all alternative treatments of financial information within Generally Accepted Accounting Principles (GAAP) that have been discussed with Management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the independent auditor; and, iii) other material written communications between the independent auditor and Management.
15. Take all reasonable steps to satisfy itself that officers and directors or persons acting under their direction are aware that they are prohibited from coercing, manipulating, misleading or fraudulently influencing the independent auditor when the person knew or should have known that the action could result in rendering the financial statements materially misleading.
16. Upon completion of the annual audit, review the following with Management and the independent auditor:
    - The annual financial statements, including related footnotes and the MD&A (Management's Discussion and Analysis of Financial Condition and Results of Operations), to be included in Nexen's Annual Report filed with Canadian and U.S. regulatory agencies.
    - The significant accounting judgements and reporting principles, practices and procedures applied by Nexen in preparing its financial statements, including any newly adopted accounting policies and the reasons for their adoption.
    - Any transactions accounted for by Nexen where Management has obtained opinion letters providing that hypothetical transactions accounted for in a similar manner are accounted for in accordance with GAAP (letters issued in accordance with Statement of Auditing Standards 50 - "Reports on the Application of Accounting Principles").
    - The results of the combined audit of the financial statements and internal control over financial reporting; the related audit reports on the financial statements and internal control over financial reporting; and, whether any limitations were placed on the scope or nature of the audit procedures.
    - Significant changes to the audit plan, if any, and any serious disputes or difficulties with Management encountered during the audit, including any problems or disagreements with Management which, if not satisfactorily resolved, would have caused the independent auditor to issue a non standard report on Nexen's financial statements.
    - The co-operation received by the independent auditor during its audit, including access to all requested records, data and information.
    - Any other matters not described above that are required to be communicated by the independent auditor to the Committee pursuant to auditing standards, rules or regulations in effect at the time.

Risk Management

17. Discuss guidelines and policies with respect to risk assessment and risk management, including the processes Management uses to assess and manage Nexen's risk. Receive reports from Management and the Finance Committee with respect to risk assessment, risk management and major financial risk exposures. Discuss major financial risk exposures and steps Management has taken to monitor and manage such exposures.

Financial Statements and Disclosure

18. At least annually, as part of the review of the annual or quarterly financial statements, receive an oral report from Nexen's general counsel concerning legal and regulatory matters that may have a material impact on the financial statements.
19. Based on discussions with Management and the independent auditor, in the Committee's discretion, recommend to the Board whether the annual financial statements should be approved for inclusion in Nexen's Annual Report filed with Canadian and U.S. regulatory agencies.
20. Review the general types and presentation format of information that it is appropriate for Nexen to disclose in quarterly or annual earnings news releases and annual cash flow or production guidance. Annual production and cash flow guidance is approved through the Board's approval of the Annual Operating Plan. If such guidance is required to be updated during the year, the Committee Chair shall review and approve the updates and report any such change to the Committee. Review with Management and the independent auditor the quarterly financial statements and MD&A and, subject to delegation by the Board to the Committee and in the Committee's discretion, approve and/or recommend to the Board for consideration the quarterly results, financial statements, MD&A, related reports and all earnings news releases prior to filing them with or furnishing them to the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including the results of the independent auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, any disagreements between the independent auditor and Management and the impact on the financial statements of significant events, transactions or changes in accounting principles or estimates that potentially affect the quality of financial reporting.
21. Receive reports, from time to time, as required, from the Chair or other representative of each of the Finance Committee and the Reserves Review Committee and discuss with them issues of relevance to both the Committee and each of the Finance Committee and the Reserves Review Committee.

Internal Control Process

22. Review with Management, Corporate Audit and the independent auditor, Nexen's internal control over financial reporting, any significant deficiencies or material weaknesses in their design or operation, any proposed major changes to them and any fraud involving Management or other employees who have a significant role in Nexen's internal control over financial reporting.
23. Review the independent auditor's annual attestation of the internal control over financial reporting structure and procedures.
24. Review the performance and independence of the Corporate Audit function and whether Corporate Audit has had full access to Nexen's books, records and personnel.
25. Review and approve the proposed annual Corporate Audit Plan including assessment of major risks, areas of focus, responsibilities and objectives, and staffing.
26. Receive periodic reports from Corporate Audit addressing i) progress on the Corporate Audit Plan, including any significant changes to it; ii) significant internal audit findings, including issues as to the adequacy of internal control over financial reporting and any procedures implemented in light of significant control deficiencies; and, iii) any significant internal fraud issues.

27. Review with Management, the Chief Financial Officer, the Chief Legal Officer, Corporate Audit and the independent auditor the methods used to establish and monitor Nexen's policies with respect to unethical or illegal activities by employees that may have a material impact on the financial statements.
28. Meet with Management, Corporate Audit and the independent auditor to discuss any relevant significant recommendations that the independent auditor may have, particularly those characterized as "material" or "serious". (Typically, such recommendations will be presented by the independent auditor in the form of a Letter of Comments and Recommendations to the Committee.) Review responses of Management to the Letter of Comments and Recommendations from the independent auditor and receive follow up reports on action taken concerning the recommendations.
29. Receive a report, at least annually, from the Reserves Review Committee on Nexen's oil and gas reserves, and on the findings of any independent qualified reserves consultants.
30. Review any appointment or dismissal of the senior internal audit executive (Director, Corporate Audit).
31. Review with Management and the independent auditor any correspondence with regulators or government agencies and any employee complaints or published reports which raise material issues regarding Nexen's financial statements or accounting policies.
32. Review with Management and the independent auditor any off-balance sheet financing mechanisms, transactions or obligations of Nexen.
33. Regularly review with Management and the independent auditor any related party transactions.
34. Review with the independent auditor the quality of Nexen's accounting personnel. Review with Management the responsiveness of the independent auditor to Nexen's needs.
35. Receive a report, at least annually, from Management on Nexen's community investment budget and Nexen and employee donations.

Compliance

36. Prepare a letter for the annual report to shareholders and the Annual Report filed with Canadian and U.S. regulatory agencies, disclosing whether or not, with respect to the prior fiscal year i) Management has reviewed the audited financial statements with the Committee, including a discussion of the quality of the accounting principles as applied and significant judgments affecting Nexen's financial statements; ii) the independent auditor has discussed with the Committee the independent auditor's judgments of the quality of those principles as applied and judgments referenced in i) above under the circumstances; iii) the members of the Committee have discussed among themselves, without Management or the independent auditor present, the information disclosed to the Committee described in i) and ii) above; and, iv) the Committee, in reliance on the review and discussions conducted with Management and the independent auditor pursuant to i) and ii) above, believes that Nexen's financial statements are fairly presented in conformity with Canadian GAAP in all material respects and that the reconciliation of Nexen's financial statements to U.S. GAAP complies with the requirements of the Securities Exchange Act of 1934 (1934 Act).
37. Receive reports, as required, from Management, Nexen's Director, Corporate Audit or, to the best of their knowledge, the independent auditor that Nexen's subsidiary / foreign affiliated entities are in conformity with applicable legal requirements and Our Integrity Guide, including disclosures of insider and affiliated party transactions.
38. Review with the independent auditor any reports required to be submitted to the Committee under Section 10A of the 1934 Act (regarding the detection of illegal acts, the identification of related party transactions and the evaluation of whether there is substantial doubt about the ability of Nexen to continue as a going concern).

Committee Reporting

39. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.
40. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of Nexen's financial statements, Nexen's compliance with applicable law, the performance and independence of Nexen's independent auditor, and the performance of the Corporate Audit function.
41. Annually review and approve the Committee's report for inclusion in the Proxy Circular.
42. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

43. Meet at least four times annually and as many additional times as needed to carry out its duties effectively. The Committee may, on occasion and in appropriate circumstances, hold a meeting by telephone conference call.
44. Meet in separate, non-management, closed sessions with the Director, Corporate Audit at each regularly scheduled meeting.
45. Meet in separate, non-management, closed sessions with the independent auditor at each regularly scheduled meeting.
46. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.
47. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

Committee Governance

48. Once or more annually, as the Corporate Governance and Nominating Committee (CGN Committee) decides, receive for consideration that Committee's evaluation of this Mandate and any recommended changes. Review and assess the CGN Committee's recommended changes and make recommendations to the Board for consideration.

Advisors / Resources

49. Have the sole authority to retain, oversee, compensate and terminate independent advisors who assist the Committee in its activities.
50. Receive adequate funding from Nexen for independent advisors and ordinary administrative expenses that are needed or appropriate for the Committee to carry out its duties.

Other

51. Carry out any other appropriate duties and responsibilities assigned by the Board.
52. To honor the spirit and intent of applicable law as it evolves, authority to make minor technical amendments to this Mandate is delegated to the Secretary, who will report any amendments to the CGN Committee at its next meeting.

Approved: December 6, 2010

Nexen's Long Lake oil sands facility

Management's Discussion and Analysis

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

The following should be read in conjunction with the Consolidated Financial Statements of Nexen Inc. as at and for the year ended December 31, 2010. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 24 to the Consolidated Financial Statements. The date of this discussion is February 16, 2011. Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Oil and gas volumes, reserves and related performance measures are presented on a working interest before royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

Investors should read the "Forward-Looking Statements" on page 115.

Proved and probable reserves estimates included in this MD&A have been prepared in accordance with SEC requirements. Canadian investors should read the "Special Note to Canadian Investors" on page 34 in our AIF for the year ended December 31, 2010.

EXECUTIVE SUMMARY

2010 Results

(Cdn$ millions, except otherwise indicated)	**2010**	**2009**	**2008**
Production before Royalties (mboe/d)[1,2]	246	243	250
Production after Royalties (mboe/d)[2]	220	213	210
Total Revenues and Other Income[2]	7,226	5,804	8,237
Cash Flow from Operations[2,3]	2,130	2,215	4,229
Net Income from Continuing Operations	572	512	1,602
Net Income[2]	1,197	536	1,715
Earnings per Common Share from Continuing Operations, Basic ($/share)	1.09	0.98	3.05
Earnings per Common Share from Continuing Operations, Diluted ($/share)	1.08	0.96	3.01
Earnings per Common Share, Basic[2] ($/share)	2.28	1.03	3.26
Earnings per Common Share, Diluted[2] ($/share)	2.27	1.01	3.22
Cash Dividend ($/share)	0.20	0.20	0.18
Total Assets	21,907	22,900	22,155
Net Debt[4]	4,074	5,551	4,575

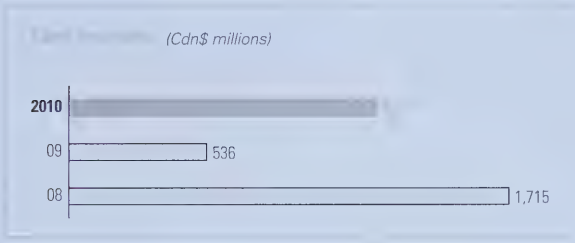
1 *Production before royalties reflects our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. We report bitumen as production until we are consistently operating the upgrader and producing PSC™.*

2 *Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).*

3 *Cash flow from operations is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 114.*

4 *Net debt is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 114.*

Strong production rates and strengthening commodity prices delivered solid financial results in 2010 as cash flow from operations during the year exceeded $2.1 billion and net income was approximately $1.2 billion. Our successful non-core asset disposition program generated proceeds of almost $1.3 billion and net pre-tax gains of $740 million in 2010. This excludes the sale of our interest in Canexus in early 2011 which generated cash proceeds of $458 million. We received the Canexus proceeds in February 2011 and we expect to recognize a gain of approximately $250 to $300 million in the first quarter of 2011.



WTI and Brent crude oil prices both increased 29% from the previous year to average about US$80/bbl. The benefit from these higher commodity prices was muted by the stronger Canadian dollar as the US/Canadian average exchange rate strengthened from 88 cents in 2009 to 97 cents this year. Our realized oil and gas price increased 17% over the same period to average $70.11/boe.

Production before royalties averaged 246,000 boe/d in 2010, up slightly from last year. Excluding the impact from the sale of the heavy oil assets midway through the year, production increased 5% over last year. A full year of production at Longhorn in the Gulf of Mexico and at Ettrick in the North Sea, and continued bitumen ramp–up at Long Lake, increased production volumes in 2010. UK production was higher than last year despite third-party facilities outages as well as planned downtime to commission the Buzzard fourth platform that temporarily reduced production. Our fourth quarter production averaged 246,000 boe/d, 3% higher than the previous quarter. This increase reflects new production from our Horn River shale gas, improved uptime at Syncrude and growth in the UK. In 2011, we expect production to range between 230,000 and 270,000 boe/d before royalties.

Our financial position is strong. For the past several years, we invested significant capital in a number of major development projects such as Buzzard and Long Lake. With the bulk of investment in these projects behind us and new production from Ettrick, Longhorn and Long Lake on stream, we expect to fund our next generation of new growth projects from operating cash flows. These projects include Golden Eagle in the UK North Sea, Usan offshore West Africa (approximately 85% complete), future oil sands insitu phases and shale gas in the Horn River Basin in northeast British Columbia, as well as several exploration prospects.

Our net debt decreased 25% or approximately $1.5 billion during the year primarily as a result of our non-core asset disposition program. Net debt was further reduced by $458 million in early 2011 upon receipt of the proceeds from the Canexus sale.

Our available liquidity is currently $4 billion, comprised of cash and undrawn committed credit facilities, most of which are available until 2014. The average term-to-maturity of our debt is approximately 21 years.

Strategy Progress

(Cdn$ millions)	2010	2009	2008
Oil and Gas Capital Investment, including Acquisitions	2,492	3,303	3,054
Proved Oil and Gas Reserves before Royalties (mmboe)[1]	987	1,011	988
Proved Oil and Gas Reserves after Royalties (mmboe)[1]	903	920	926

1 Includes developed and undeveloped proved reserves as at December 31.

Our strategy is to build a sustainable energy company focused in three growth areas: oil sands, conventional exploration and development and unconventional gas. Our investment in these areas generated the following results in 2010:

- **conventional exploration and development**—our conventional exploration program was focused in the North Sea, deep-water Gulf of Mexico and offshore West Africa. We advanced the development of our Usan field toward first production in 2012. In the UK North Sea we advanced our Golden Eagle/Hobby project by capturing land adjacent to the field, gaining partner support for the development plan and filing a Field Development Plan with the regulatory authority. We also made a significant discovery at Appomattox in the US Gulf of Mexico and several other discoveries around our existing infrastructure in the North Sea.
- **oil sands**—we commenced actions to fill the upgrader through accelerated pad drilling, increase steam capacity, enhancing independence between the SAGD and upgrader operations, and increase water–handling capacity. We have also developed a bitumen leading strategy at Kinosis to simplify the development while retaining the option to capture the benefits of upgrading and our integrated process.
- **unconventional gas**—we delivered a drilling, fracing and completions program at industry-leading pace with a 100% success rate. We commenced production of the eight–well program and shale gas production is approaching expectations of 50 mmcf/d and is giving us the desired information on well design. We also acquired additional acreage in the Cordova and Liard basins, making us one of the largest acreage holders in this highly attractive area.

During 2010, our proved oil and gas reserves additions replaced 114% of our oil and gas production (135% after royalties).

	Oil and Gas	
(mmboe)	**Before Royalties**	**After Royalties**
Production[1]	89	79
Proved Reserve Changes excluding Production		
Net Additions	100	94
Economic Revisions	1	13
	101	107

1 Production for Long Lake is presented in synthetic barrels as our reserves are measured in synthetic oil barrels. For comparative purposes, production volumes before royalties using bitumen barrels would be 90 mmboe before royalties (80 after royalties).

The majority of our additions relate to our exploration successes at Golden Eagle, Rochelle and Blackbird, strong production performance at Buzzard and Telford in the UK and Yemen, and the recognition of shale gas reserves at our Horn River Basin development. During the year, we sold 36 mmboe (30 after royalties) as part of our heavy oil disposition.

Our 2010 proved reserve additions are not necessarily indicative of future annual additions which will be dependent on such factors as oil and gas prices, capital allocations, nature of our drilling programs, exploration success and expected timing of proceeding with development of reserves discovered. Management uses the reserves replacement ratio as a measure for our success in replacing reserves produced. We look at various time periods when considering this ratio.

Outlook

For 2011, we expect our annual production will range between 230,000 and 270,000 boe/d (210,000 to 240,000 boe/d after royalties). The range is driven by the pace of ramp–up at Long Lake, run-times at Buzzard and Scott/Telford in the North Sea and the timing of new volumes from our Horn River shale gas program. We expect to grow production after royalties by approximately 4% assuming the midpoint of our guidance range and 7% after adjusting for the sale of our heavy oil properties in 2010.

We expect our 2011 cash flow from operations to range from $2.1 to $2.8 billion assuming WTI of US$75 to US$90/bbl. Since late December 2010, international oil prices have risen faster than WTI with Brent trading at a premium of $18/bbl. With 80% of our oil production receiving international prices, we expect to see the benefits of this in 2011 as our cash flow sensitivity is $270 million annually per US$10/bbl change in Brent, after tax.

In 2011, we plan to invest between $2.4 and $2.7 billion in capital projects which we expect to finance through operating cash flows and existing cash on hand. Our capital program is expected to advance our future growth areas as we move forward with developing several major identified projects, including Usan, Golden Eagle, Knotty Head and Horn River shale gas. Our 2011 capital investment plans include investing between $600 and $650 million on drilling 22 exploration and appraisal wells, primarily in the North Sea and the Gulf of Mexico.

CAPITAL INVESTMENT

(Cdn$ millions)	**Estimated 2011**	**2010**	**2009**
Conventional Development and Exploration			
North Sea	750	766	684
West Africa	500	495	507
United States	250	261	321
Other	50	166[1]	187
	1,500–1,600	1,688	1,699
Oil Sands			
Long Lake, Kinosis and Other Insitu	425	228	1,303
Syncrude	150	100	87
	550–600	328	1,390
Unconventional Gas	300–350	476	214
Total Oil and Gas	**2,350–2,600**	**2,492**	**3,303**
Corporate, Chemicals and Other	50–100	210	275
Total Capital	**2,400–2,700**	**2,702**	**3,578**

1 Includes capital in Canada ($78 million) and Yemen ($52 million).

Our strategy and capital programs are focused on growing value for our shareholders responsibly. To maximize value, we invest in:

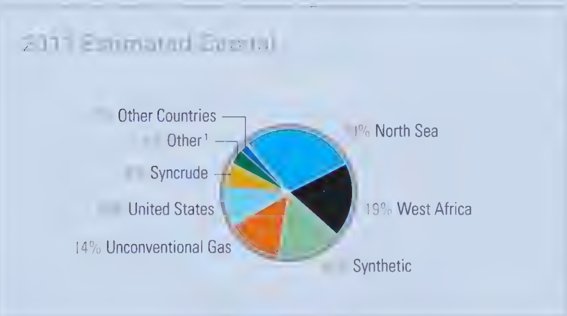
- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow in the medium term; and
- appraisal, exploration and new growth projects for longer-term growth.

We invest in key focus areas including Athabasca oil sands, Canadian unconventional shale gas, and offshore opportunities in the North Sea, deep-water Gulf of Mexico, and West Africa—areas we believe have attractive fiscal terms, significant remaining opportunity and where we believe we have a competitive advantage.

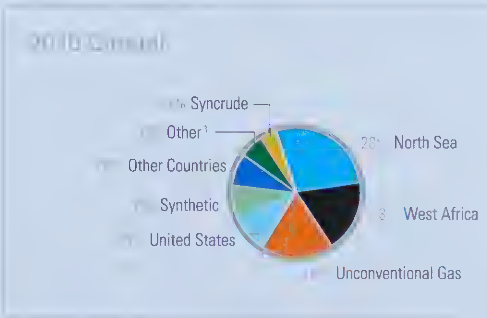
In 2010, we invested $2.5 billion in oil and gas activities and added 101 mmboe of proved reserves and 25 mmboe of probable reserves before royalties. We are not yet carrying any proved or probable reserves for our discoveries in the Appomattox area, at Knotty Head or at Owowo. A summary of our 2010 capital investment program and reserve additions are shown in the table below. In this section, production and reserves are before royalties. Additional information on our oil and gas reserves can be found in Reserves, Production and Related Information on page 25 of our AIF.

	Capital Investment[1] (Cdn$ millions)	Production[2] (mmboe)	Proved Reserve Additions[2] (mmboe)	Probable Reserve Additions[2] (mmboe)
Conventional Exploration and Production	1,688	76	80	3
Oil Sands	328	12	8	5
Unconventional Gas	476	1	13	17
Total Oil and Gas	**2,492**	**89**	**101**	**25**

1 Oil and gas capital investment includes $100 million of cash outflows related to geological and geophysical expenditures.
2 Before royalties.



1 Energy Marketing, Corporate and Other.



1 Energy Marketing, Corporate and Other.

Conventional Exploration and Production

NORTH SEA

We continue to have significant success in the North Sea. Since entering the basin in late 2004, we have gone from 100 million boe of proved reserves to 255 million boe of produced and remaining proved reserves. Buzzard is one of the drivers to this growth. We have continued to find more oil than originally expected, allowing us to recognize increased reserves, identify further development drilling locations and extend the production plateau for several more years.

In 2010, we invested $766 million in the North Sea, including $305 million on exploration and appraisal activities. We drilled successful wells at Polecat and West Rochelle, and a successful follow up to our Blackbird discovery.

At Buzzard, we spent $80 million to install the topsides and commission the fourth platform. This will enable us to produce our wells with higher H_2S concentrations. We added 22 million boe of proved reserves here, primarily attributable to successful drilling and production performance which resulted in increases in both reservoir size and recovery factor.

Also during the year, we made significant progress in advancing our discoveries in the Golden Eagle area. We expanded the acreage position to follow the trend to the north. In late 2010, we filed a field development plan with the regulatory authority. Our discoveries are large enough to require standalone facilities and are economic with oil prices significantly lower than current prices. Facility design size is expected to be 70,000 boe/d (gross). Following equalization of the blocks, we will have a 36.5% working interest and will operate the project.

We expect to sanction the development in 2011. To date, we have booked 34 million boe of proved reserves and an additional 16 million boe of probable reserves for this area.

We are also having success with our drilling program centered around our infrastructure. At Scott/Telford, we invested $150 million and added six million boe of proved reserves from development drilling. We anticipate further upside in the area with opportunities for quick tie-backs. We also added five million boe of proved reserves for Rochelle, a tie-back development to our Scott platform.

During the quarter, the UK Government announced that, subject to completion of the award process, we were the successful applicant for 10 licences covering 18 blocks in the UK North Sea 26th Offshore Oil and Gas Licensing Round. Most of these blocks are near our existing acreage and infrastructure, and are expected to enhance our ongoing exploration program.

OFFSHORE WEST AFRICA

We made excellent progress on the development of the Usan field, offshore West Africa, and remain on track to achieve first oil in 2012. The development includes a floating production, storage and offloading vessel (FPSO) with the ability to process 180,000 bbls/d (36,000 net to us) and store up to two million barrels of oil. FPSO fabrication is nearing completion and the vessel will soon be towed to Nigeria for field installation. The project is approximately 85% complete and is expected to generate $850 million of net annual cash flow at WTI US$90/bbl. We have a 20% interest in exploration and development on this block along with partners ExxonMobil, Chevron and operator Total E&P Nigeria Limited.

UNITED STATES

In the Gulf of Mexico, our capital program is focused on the deep–water and in 2010 we invested $178 million on exploration and appraisal, and $83 million on our deep–water and shelf producing assets.

Our exploration program resulted in a discovery at Appomattox, located in Mississippi Canyon blocks 391 and 392. An exploration well and two appraisal sidetracks have confirmed this to be a significant oil discovery. We plan to further appraise this discovery once drilling permits are received.

Elsewhere in the deep–water, we drilled an appraisal well at Knotty Head and the joint venture participants have entered into a letter of intent to unitize the field with Hess' Pony discovery. We are working on having an integrated project team in place later in 2011 to work on a joint development plan to move the Knotty Head and Pony discoveries towards sanctioning. As we advance our development concept, we expect to book reserves here.

We are waiting on drilling permits from the Bureau of Ocean Energy Management (BOEM) to drill two exploration prospects, Kakuna and Angel Fire, in the area near our Knotty Head discovery. We have negotiated a reduced standby rate on one of our rigs and have declared force majeure on the other. The estimated maximum 2011 cost to us for these costs is $65 million, assuming we cannot commence drilling until the end of the second quarter. We are actively pursuing ways to reduce this cost.

Early in 2010, we initiated a process to market a portion of our Gulf of Mexico exploration portfolio including the farm-down of higher working interest prospects. With the Macondo incident, we focused on farm-outs on a well-by-well basis of our near-term drilling prospects. Negotiations with several parties are underway and are expected to be completed before the wells commence drilling.

YEMEN

In 2010, we invested $52 million and added 6 million boe of proved reserves. We continue to focus on maximizing the value of these assets over the remaining life of the contracts. We are currently in discussions with the Yemen government on a contract extension.

Oil Sands

We invested $228 million on the Long Lake project and other joint venture lands. The focus of the capital has been on the electric submersible pump (ESP) installation program, activities to increase production and reliability at Long Lake, advancing Kinosis and on our other future oil sands developments.

Ongoing initiatives to support the ramp-up at Long Lake include accelerated drilling of pads 12 and 13 which will be ready for steaming in 2012; the addition of two once-through steam generators that will add 10 to 15% to our existing steam capacity and be ready for service late 2012; and creating greater independence between the SAGD operations and upgrader by increasing gas inlet capacity and adding a diluent recovery unit. These investments represent $400 to $500 million of capital (net to us), over the next few years, of which approximately half relates to the additional pads and represents an acceleration of capital spending.

We are also advancing engineering activities on Kinosis to develop two 40,000 bbl/d SAGD projects. This development plan provides us with the option to add an upgrader when SAGD projects are ramped up to capacity.

We are monitoring our partner's financial status and assessing their capabilities to continue funding their share of the capital spending. As the potential for this type of situation was contemplated at the time we entered into the joint venture we believe our interests are well protected.

Unconventional Gas

We made considerable progress in advancing our northeast BC shale gas play. We successfully drilled and brought on-stream our eight-well pad, and commenced drilling another nine-well pad late in the year. We more than doubled our acreage position to 300,000 acres (100% working interest), making us one of the largest leaseholders in this attractive play.

We invested in the drilling, completion and tie-in of the eight-well pad and expansion of in-field facilities. The drilling campaign was completed in under 25 days per well. Compared to our previous program, these wells were drilled in 35% fewer days and were 80% longer. These wells were completed with 18 fracs per well at an industry-leading pace of 3.5 fracs per day with a 100% success rate. We recently started producing these wells and are experiencing initial production rates of 8 to 15 mmcf/d per well. With the success we're seeing on our activities, we expect to be able to make a 10% return with NYMEX gas prices as low as US$4.00 to US$4.50/mcf.

We recently commenced drilling our nine-well pad and expect fracing and completion activities this summer. We are also progressing plans to drill an 18-well pad in the second half of 2011. First shale gas production from the nine-well pad is expected in the fourth quarter of 2011 with production from the 18-well pad expected in late 2012.

Our shale gas capital includes the purchase of almost 175,000 acres of land in the Cordova and Liard basins. This brings our total acreage in northeast BC to over 300,000 acres (100% working interest).

We also recently commenced a process to seek a joint venture partner for various portions of our northeast BC shale gas acreage. This will allow us to monetize a portion of the value that we have created from the success we have had capturing high quality acreage, understanding the reservoir and reducing our costs. We have engaged Bank of America Merrill Lynch as our advisors on this process.

Year-to-Year Change in Net Income

(Cdn$ millions)	2010 vs 2009	2009 vs 2008
Net Income for 2009 and 2008 [1]	**536**	**1,715**
Favourable (unfavourable) variances:[2]		
Production Volumes, After Royalties		
Crude Oil	244	(137)
Natural Gas	57	36
Change in Crude Oil Inventory	70	(80)
Total Volume Variance	371	(181)
Realized Commodity Prices		
Crude Oil	711	(1,871)
Natural Gas	27	(313)
Total Price Variance	738	(2,184)
Oil & Gas Operating Expense	(385)	9
Oil & Gas Depreciation, Depletion, Amortization and Impairment	29	241
Exploration Expense	(26)	100
Non-core Asset Disposition Gains	740	–
Energy Marketing Revenue, Net	(322)	605
Chemicals Contribution	(48)	73
General and Administrative Expense	15	(240)
Interest Expense	(12)	(218)
Current Income Taxes	(356)	83
Future Income Taxes	(148)	1,114
Change in Fair Value of Crude Oil Put Options	210	(454)
Other	(145)	(127)
Net Income for 2010 and 2009 [1]	**1,197**	**536**

1 Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).
2 All amounts are presented before provision for income taxes.

Significant variances in net income are explained in the sections that follow.

Year-to-Year Change in Net Income *(Cdn$ millions)*

Production

	2010		2009		2008	
	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties
Oil and Liquids (mbbls/d)						
United Kingdom	104.9	104.8	98.0	98.0	99.7	99.7
Canada[2]	7.5	5.8	14.6	11.4	16.2	12.3
Long Lake Bitumen[3]	15.9	15.1	7.9	7.9	3.9	3.9
Syncrude	21.2	19.6	20.2	18.6	20.9	18.2
United States	9.9	9.0	10.5	9.5	9.3	8.1
Yemen	41.3	23.1	49.9	29.8	56.6	30.6
Other Countries	2.1	1.9	3.5	3.2	5.8	5.3
	202.8	179.3	204.6	178.4	212.4	178.1
Natural Gas (mmcf/d)						
United Kingdom	35	35	24	24	18	18
Canada[2]	126	116	139	128	131	109
United States	99	94	65	57	78	66
	260	245	228	209	227	193
Total (mboe/d)	**246**	**220**	**243**	**213**	**250**	**210**

1 We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.
2 Includes the following production from discontinued operations. See Notes 18 and 20 to our Consolidated Financial Statements.
3 We report bitumen as production until we are consistently operating the upgrader and producing PSC™.

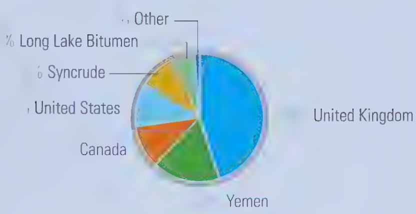
	2010	2009	2008
Before Royalties			
Crude Oil and NGLs (mbbls/d)	7.5	14.6	16.2
Natural Gas (mmcf/d)	6	13	15
After Royalties			
Crude Oil and NGLs (mbbls/d)	5.8	11.4	12.3
Natural Gas (mmcf/d)	5	11	12

2010 VS 2009—HIGHER VOLUMES INCREASED INCOME BY $371 MILLION

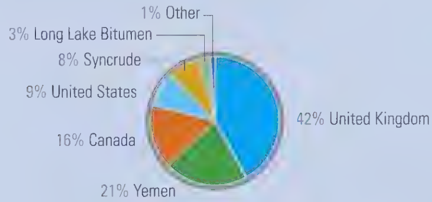
Production before royalties averaged 246,000 boe/d, slightly higher than 2009. After adjusting for the impact of heavy oil volumes disposed midway through the year, production increased 5% over last year. A full year of production at Ettrick in the North Sea and at Longhorn in the Gulf of Mexico, and higher bitumen production at Long Lake, offset natural declines in Yemen. Production after royalties increased 3% from the prior year to average 220,000 boe/d, as we produced more from lower royalty jurisdictions.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2009 Production	243	213
Production Related to Disposed Properties	(8)	(7)
	235	206
Production Changes		
United Kingdom	9	9
Long Lake Bitumen	8	7
United States	6	6
Yemen	(9)	(7)
Other	(3)	(1)
2010 Production	**246**	**220**



2009 Production before Royalties



Fourth quarter production before royalties averaged 246,000 boe/d (227,000 after royalties), 7,000 boe/d higher than the prior quarter. The increase was due to improved uptime at Scott/Telford in the UK North Sea and at Syncrude, higher production rates at Long Lake, and new shale gas volumes brought on-line. Compared to the fourth quarter of 2009, production is 19,000 boe/d lower. The decrease reflects the disposition of our Canadian heavy oil assets in the third quarter of 2010, natural declines at Yemen and start-up activities of the fourth platform at Buzzard.

Production volumes discussed in this section represent our working interest before royalties.

United Kingdom

UK production for the year increased 9% from last year to average 110,700 boe/d, primarily as a result of a full year of production at Ettrick, which came on stream mid 2009.

Buzzard production was down slightly from 2009 due to planned downtime to complete installation and commissioning of the H_2S processing facilities on the fourth platform. Commissioning is proceeding well and we are near to having it fully integrated with the existing production systems. With the increased H_2S handling capability, we expect to be able to continue to maintain our high netback Buzzard production at plateau for many more years. We have identified drilling locations to continue our development program at Buzzard into 2013, which is expected to extend our production plateau.

A full year of production from our Ettrick field contributed 14,500 boe/d to our annual average volumes. This was higher than last year when it averaged 4,300 boe/d, as the facilities came on stream in the third quarter of 2009.

Scott/Telford averaged 13,900 boe/d, 3% higher than 2009. The increased production from the successful step-out development well drilled in the third quarter of 2009 was offset by an eight week shut-in during the third quarter of 2010 due to a valve failure on the third-party owned Forties pipeline system. Production in the fourth quarter was also affected by the repairs on the gas export system, which have since been resolved. Production from our non-operated fields at Duart and Farragon averaged 1,800 boe/d in 2010.

In 2011, we expect production from the North Sea to average between 110,000 and 130,000 boe/d. Increases are expected to come from improved uptime at Buzzard, Scott/Telford and Ettrick.

Canada

Production in Canada decreased 25% in 2010 primarily as a result of the disposition of our heavy oil assets. Excluding the impact of the disposition, Canadian production decreased 5% from last year. Coalbed methane (CBM) production decreased 9% from 2009 due to natural declines, while our maturing natural gas fields in the Medicine Hat region and the Balzac field were down 12% as we limited investment in conventional natural gas as a result of low natural gas prices.

We continue to invest in shale gas in the Dilly Creek area of the Horn River Basin in northeast British Columbia. During the year, we successfully completed a 144 frac program on our eight-well pad. We recently started producing these wells and are experiencing initial production rates of 8 to 15 mmcf/d per well. We plan to bring our nine-well pad on stream in 2011 with first production expected in the fourth quarter. We expect our share of production from Canada to average between 18,000 and 26,000 boe/d in 2011.

Long Lake

Bitumen volumes have more than doubled following the successful facility turnaround in the third quarter of 2009 when we replaced valves in the water treatment system, cleaned out the hot lime softeners and isolated the water treatment trains.

In December, the project produced 29,000 bbls/d (gross), matching our previous monthly high achieved in October. We generated positive operating cash flow for the month, the second time we have achieved this milestone. January production has averaged 27,000 bbls/d, reflecting steam interruptions and downhole pump failures.

During December and January, we injected our highest steam volumes of 172,000 and 156,000 bbls/d, respectively. While fluid returns have risen, the bitumen production has not increased proportional to the steam injection. While some lag between steam increasing and bitumen production increasing is expected, we also believe some of the steam is heating high water saturation zones. Our experience on the pilot wells and Pad 7N has given us the confidence that once these zones are heated, bitumen rates and steam–to–oil ratios (SORs) should improve. Our geologic data analysis indicates higher water saturation zones make up only 3 to 5% of our reservoir by volume.

Our three pilot wells were drilled on an area of the lease with a higher concentration of these zones. The SOR on these wells initially declined to under 4, and then began to rise as the steam encountered these zones. The pilot was temporarily suspended in 2006. With the start-up of the commercial SAGD operation in 2008, we re-heated the pilot wells and after steaming through the zone of higher water saturation, two of those wells are now producing in line with our design expectations of 700 bbls/d per well pair of oil at an SOR of 3.0, while the third well is restricted due to mechanical well bore issues.

We also saw this behavior on Pad 7N, which is located on some of our highest quality reservoirs. Once again, after ramping-up quickly, bitumen volumes stopped growing and SORs rose as we encountered a high water saturation zone. Once we steamed through it, performance improved and now it is, as expected, our best performing pad with five wells averaging 1,200 bbls/d per well pair at an SOR of 2.3.

Our experiences with the pilot wells and Pad 7N have provided us with valuable knowledge in dealing with our reservoir. We have learned that it is important to continue to inject consistent steam when we encounter these high water saturation zones and to lift all produced fluids with appropriate pumping and water-handling capacity. While we heat through them, there are times when we are returning up to 10% more water than we are injecting as opposed to the more usual 5 to 10% water losses. This occurs as the steam displaces formation water in these zones. As we currently have limited water disposal capacity this results in the need to limit production of fluids to achieve overall water balance with a resulting impact on bitumen volumes. We expect to increase our water disposal capacity in the next few months using existing disposal well capacity and low cost de-bottlenecking of facilities.

Various initiatives are underway to move us towards achieving our expectations of 600 to 800 bbls/d per well pair of bitumen at an SOR of 3 to 4. The increased reliability and availability of steam is allowing us to heat through these high water saturation zones faster. The expansion of our gas inlet capacity will allow us to generate more steam, with more consistent fuel availability independent of day-to-day upgrader operations. Pads 12 and 13 are expected to be available for start-up next year, and the addition of two once-through steam generators will increase our steam capacity by late next year. In the meantime, bitumen rates and SORs will be variable as we steam through these zones with higher water saturations.

Syncrude

Syncrude production increased 5% from last year to average 21,200 boe/d for the year. Production in 2010 was impacted by several factors including a scheduled turnaround of the LC finer and Coker 8-1 as well as unscheduled maintenance on both the sour water treatment and vacuum distillation units. In 2011, we expect our share of production to average between 20,000 and 24,000 boe/d.

United States

Production in the Gulf of Mexico increased 5,100 boe/d from 2009, primarily as a result of a full year of production from our non-operated Longhorn development, which came on stream in late 2009. This was partially offset by natural field declines at Aspen and Gunnison. Our shelf production decreased 7% from last year as a result of natural declines and limited capital investment in these mature fields.

The drilling moratorium in the Gulf of Mexico had no significant impact on our shelf and deep-water production during the year. We expect our share of production from the Gulf of Mexico to average between 20,000 and 28,000 boe/d in 2011.

Yemen

Production in Yemen decreased 17% compared to last year, consistent with our expectations as the field matures and development drilling is reduced. During the year, we drilled 13 development wells at Masila and six development wells at Block 51, as we concentrate our drilling program on maximizing reserve recoveries and economic returns during the remaining term of the contract. We expect our share of Yemen production to average between 28,000 and 35,000 boe/d in 2011.

Our discussions with the Yemen government and our partners for a five-year Masila contract extension beyond the current expiration date of December 17, 2011 are ongoing. There is no assurance that this extension will be received.

Other Countries

Production from Guando in Colombia decreased to average approximately 2,100 boe/d in 2010. This decline reflected natural field declines and the reduced working interest in the field effective in the second quarter of 2009. Under the terms of our licence, our working interest in the Guando field decreased from 20 to 10% in May 2009 after cumulative production from the field reached 60 million barrels. We expect our share of production to average between 2,000 and 3,000 boe/d in 2011.

2009 VS 2008—LOWER VOLUMES DECREASED INCOME BY $181 MILLION

Production before royalties in 2009 was down 3% from 2008. Lower production in Yemen was partially offset by bitumen production at Long Lake. There were also small production declines in the UK North Sea, Canada and US Gulf of Mexico.

UK production for 2009 was 1% lower than 2008 due to planned downtime at Buzzard for pipeline maintenance, the installation of the jacket for the fourth platform and downtime to relocate the Galaxy III drilling rig. This was largely offset by the start up of Ettrick in the third quarter of 2009 and higher production at Scott/Telford as a result of a successful step-out development well at Telford.

Production in Canada (excluding oil sands) remained consistent with 2008. Slightly lower conventional production from our heavy oil assets were offset by higher CBM production rates. Bitumen production in 2009 doubled from 2008 at Long Lake as we continued to ramp up with increased steam and more wells.

Our mature Yemen fields declined as expected. Production from the Masila field declined 14% in 2009 while our East Al Hajr field on Block 51 had slight declines with successful well optimization and pressure maintenance.

Our US production fell 4% in 2009 due to natural declines in our mature shelf production. In the deep–water, production remained consistent with 2008. Longhorn was brought on stream in late 2009. This new production, with higher production volumes at Aspen, was offset by Green Canyon 6, 50 and 137, which remained shut-in following Hurricane Ike in 2008.

Commodity Prices

	2010	2009	2008
Crude Oil			
West Texas Intermediate (WTI) (US$/bbl)	79.52	61.80	99.65
Dated Brent (Brent) (US$/bbl)	79.47	61.51	96.99
Benchmark Differentials[1] (US$/bbl)			
Heavy Oil	(14.45)	(9.91)	(20.27)
Mars	(1.54)	(1.48)	(6.21)
Masila	0.09	(0.39)	(4.31)
Realized Prices from Producing Assets (Cdn$/bbl)			
United Kingdom	79.02	67.70	96.23
Canada	61.39	53.04	74.51
Oil Sands—Long Lake	77.07	–	–
Oil Sands—Syncrude	81.23	70.96	105.47
United States	76.73	65.01	104.94
Yemen	81.86	68.49	99.87
Other Countries	76.83	59.05	98.98
Corporate Average (Cdn$/bbl)	78.94	66.85	96.92
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	4.39	4.16	8.90
AECO (Cdn$/mcf)	3.92	3.92	7.71
Realized Prices from Producing Assets (Cdn$/mcf)			
United Kingdom	5.28	3.95	6.78
Canada	3.94	3.78	7.73
United States	4.97	4.67	10.07
Corporate Average (Cdn$/mcf)	4.54	4.06	8.44
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	**70.11**	**60.02**	**89.78**
Average Foreign Exchange Rate—Canadian to US Dollar	0.9709	0.8757	0.9381

1 *These differentials are a premium/(discount) to WTI.*

2010 VS 2009—HIGHER REALIZED PRICES INCREASED NET INCOME BY $738 MILLION

Crude oil prices continued to strengthen in 2010 with both WTI and Dated Brent increasing 29% compared to last year, averaging about US$79.50/bbl for the year. The impact of higher crude oil prices was partially reduced by the stronger Canadian dollar, while our realized crude oil price was 18% higher than 2009. NYMEX natural gas prices increased 6% from the prior year, while AECO stayed flat at $3.92/mcf. Our realized natural gas price increased 12% to average $4.54/mcf, primarily due to the stronger prices in the UK.

The Canadian dollar continued to strengthen against the US dollar in 2010 and exited the year above parity. This foreign exchange impact reduced our net sales by approximately $600 million, as our realized crude oil and gas prices were $8.58/bbl and $0.49/mcf lower, respectively. However, our US-dollar denominated debt, operating expenses and capital expenditures are lower when translated to Canadian dollars.

Crude Oil Reference Prices

Crude oil prices were 29% higher than 2009. WTI traded between US$65/bbl and US$90/bbl during the year. Prices responded to an imbalanced and volatile global economic recovery. The main drivers supporting crude oil prices were macro-related including a continuing rally in US equity markets, positive investment flows into commodity markets in response to the weakening US dollar and more optimistic outlooks for global economic recovery. Developing countries are experiencing strong economic growth while developed countries are recovering slowly and tentatively from a deep financially-led recession. The US Federal Reserve flagged deflation as a significant concern and signaled that it will, if necessary, engage in quantitative easing (printing money to buy US treasuries to increase market liquidity, lower interest rates and reduce the US dollar exchange rate) to stem this risk. Because oil is a US dollar based global commodity, quantitative easing

would apply upward pressure to crude oil prices, as well as encourage financial investments in oil as investors use oil to hedge their exposure to a declining US dollar.

Near-term supply/demand fundamentals tightened at the end of the year providing support for stronger crude prices. China is tightening its fiscal and monetary policies to keep inflationary pressures in check. Crude prices are vulnerable to weakening demand from China if their tightening policy proves excessive.

Geopolitical events during the year included the Macondo well blowout and Gulf of Mexico drilling ban, the Greek debt crisis, possible UN sanctions against Iran, and tensions between North and South Korea. All of these events were supportive to crude oil prices but did not have a sustained material impact on them. As OPEC's spare capacity and global inventory levels are reduced, crude oil price sensitivity to geopolitical events is likely to increase.

Crude Oil Differentials

In Canada, heavy crude oil differentials were volatile, averaging $14.45/bbl (18% of WTI). Enbridge capacity curtailments in the latter part of the year widened heavy oil differentials as heavy crude takeaway capacity was restricted. The latter half of the year saw a series of *force majeure* and pipeline capacity apportionments for Western Canadian producers. Our production was not affected by these curtailments.

The Brent/WTI differential fluctuated during the year but traded at an average discount for the year of $0.05/bbl. Approximately 60% of global crude oil production is priced off of Dated Brent prices. Historically, Brent traded at a discount to WTI because surplus North Sea crude oil has been exported to the US market. With declining North Sea crude production and exports, this differential can shift to positive or negative depending on short-term supply and demand factors. Overall, the differential favored Brent with higher premiums in the latter half of 2010 because high crude inventory levels at Cushing depressed the price of WTI and North Sea maintenance reduced supply available for export.

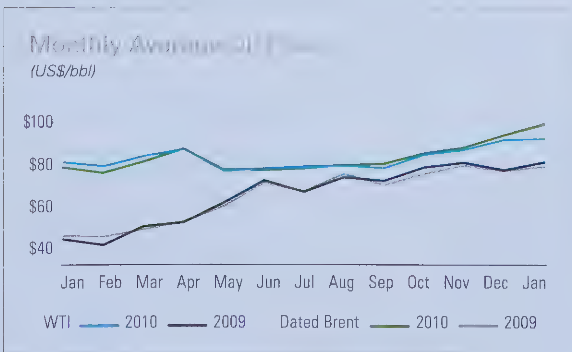
Since late December, international oil prices have risen faster than WTI with Brent trading at a premium of $10/bbl, as WTI is being held back by high regional inventories. With 80% of our oil production receiving international prices, we will see the benefits of this in 2011.

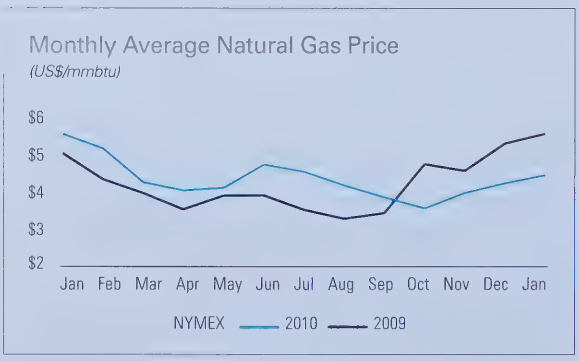
The Masila price strengthened relative to WTI following the upward movement in the Brent price and the relative strength of Asian demand. The Masila differential averaged at a premium for the year of $0.09/bbl compared to a discount of $0.39/bbl in 2009.

Mars is a medium sour crude that is priced to compete with comparable international import alternatives. It does not compete directly with WTI as there is limited pipeline capacity to move crude based from Cushing to the Gulf of Mexico refineries. As a result, the Mars differential narrowed relative to WTI mainly due to WTI's weakness, high crude oil inventories, excess global refining capacity and OPEC cuts in medium crude.

Natural Gas Reference Prices

Low NYMEX natural gas prices were driven by warm weather and high inventory levels throughout the year. Natural gas producers continue to drill shale plays to retain lands despite low prices. There was a limited spike in gas prices as a result of the winter cold weather but downward pressure on natural gas prices is likely to remain until inventory levels decrease.





2009 VS 2008—LOWER REALIZED PRICES DECREASED NET INCOME $2,184 MILLION

Crude oil prices steadily increased during 2009, after falling dramatically in the fourth quarter of 2008 due to the economic crisis. WTI averaged US$61.80/bbl for the year, down 38% from 2008, while Dated Brent decreased 37% to average US$61.51/bbl over the same period. Gas prices fluctuated during the year, with NYMEX averaging US$4.16/mmbtu and AECO averaging $3.92/mcf, decreases of 53% and 49% from 2008, respectively. The impact of lower average commodity prices was partially offset by foreign exchange savings. Our corporate average crude oil price fell 31% to $66.85/bbl, while our corporate average natural gas price was 52% lower, averaging $4.06/mcf.

In 2009, the average annual US dollar was stronger than the Canadian dollar as compared to 2008. This reduced the impact of lower benchmark commodity prices, increasing net sales by approximately $295 million. This impact on sales increased our realized crude oil and natural gas prices by approximately $4.45/bbl and $0.27/mcf, respectively.

Operating Expenses[1]

	2010		2009		2008	
(Cdn$/boe)	Before Royalties[2]	After Royalties	Before Royalties[2]	After Royalties	Before Royalties[2]	After Royalties
Conventional Oil and Gas						
United Kingdom	8.24	8.24	6.87	6.87	6.75	6.75
Canada	12.31	14.10	12.76	14.80	13.12	16.38
United States	10.02	10.76	12.58	14.10	11.57	13.48
Yemen	10.25	18.69	10.69	18.34	8.51	15.88
Other Countries	6.99	7.52	6.03	6.53	4.52	4.91
Average Conventional	9.37	10.62	9.34	10.76	8.68	10.40
Synthetic Crude Oil						
Long Lake[3]	100.09	105.17	–	–	–	–
Syncrude	36.74	39.78	35.92	39.09	36.53	42.04
Average Oil and Gas	15.67	17.62	11.66	13.33	11.04	13.18

1 *Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).*

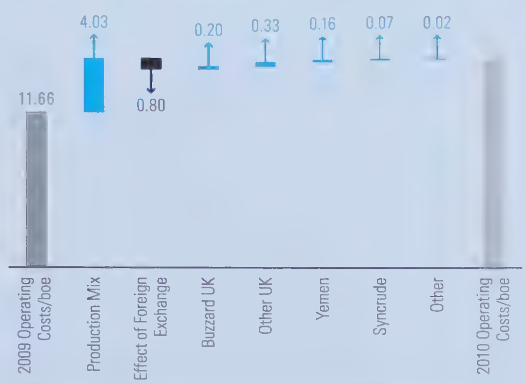
2 *Operating expenses per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.*

3 *Excludes activities related to third-party bitumen purchased, processed and sold.*

2010 VS 2009—HIGHER OPERATING EXPENSES DECREASED NET INCOME BY $385 MILLION

Operating costs increased $385 million from 2009 primarily due to costs associated with our Long Lake project. Long Lake operating costs of $373 million were expensed during the year. At January 1, 2010, we ceased capitalizing our Long Lake start-up costs. As Long Lake operating costs are mainly fixed, increasing volumes improved our per unit operating cost by about 10% from earlier in the year. When fully ramped up, we expect Long Lake operating costs to be $25 to $30/bbl. Elsewhere, a full year of operating costs at Ettrick were offset by reduced maintenance and workover costs in Yemen and the sale of our Canadian heavy oil properties in the third quarter. These production changes increased our corporate average by $4.03/boe.

Change in Corporate Aver[illegible] Operating Costs 2009 to 2010 *(Cdn$/boe)*



In the UK North Sea, Buzzard increased our corporate average by $0.20/boe due to a combination of higher maintenance activity and slightly lower production. Elsewhere in the UK, higher North Sea costs increased our corporate average by $0.33/boe. At Scott, the per unit cost increased due to maintenance downtime and third-party outages in the second half of the year.

In Yemen, lower maintenance and workover costs only partially offset the impact of production declines, which increased our corporate average cost by $0.16/boe. At Syncrude, the impact of additional operating costs was partially offset by higher production volumes. These changes increased our corporate average by $0.07/boe.

In Canada, the sale of our heavy oil properties in July reduced operating costs by $52 million as compared to last year. Our heavy oil properties had higher per unit operating costs than our corporate average.

The stronger Canadian dollar reduced our corporate average by $0.80/boe as operating costs of our international and US assets are denominated in US dollars.

2009 VS 2008—LOWER OPERATING EXPENSES INCREASED NET INCOME BY $9 MILLION

Our average oil and gas operating cost increased $0.62/boe from 2008, as lower costs in Canada and Syncrude were only partially offset by the impact of a stronger US dollar in other areas. US-dollar denominated operating costs were higher when translated to Canadian dollars, increasing our corporate average by $0.63/boe for 2009.

Changes in our production profile during 2009 increased our corporate average by $0.47/boe. Buzzard, a lower cost area, contributed a smaller percentage of our total production, year over year, compared to higher cost areas such as Scott/Telford and Ettrick.

In the UK North Sea, lower production rates at Buzzard were more than offset by reduced operating costs due to higher planned downtime and lower production tariffs and logistics costs. This reduced our corporate average by $0.21/boe. The impact of other areas in the UK North Sea reduced our corporate average by $0.38/boe. At Scott/Telford, total costs decreased while production was higher due to additional Telford production. This was somewhat offset by the start-up of the Ettrick field and FPSO vessel, where operating costs per barrel are higher than our corporate average.

In Yemen, we continue to incur costs to maintain existing well productivity to maximize reserve recoveries and slow the natural decline of the field. These costs, combined with production declines, increased our corporate average operating cost by $0.20/boe. In the US Gulf of Mexico, slightly higher operating costs combined with lower shelf production, increased our corporate average by $0.02/boe.

Canada reduced our corporate average by $0.06/boe as lower heavy oil and CBM costs were substantially offset by increased operating costs at Balzac. Our heavy oil properties experienced improved run times and less downtime, which reduced downhole workover costs. This, combined with lower utility costs, reduced operating costs by 14%. CBM costs increased as we brought more wells on stream; however, the incremental production volumes reduced our average cost per barrel. This was partially offset by increased per-unit costs at Balzac, where the impact of declining production has only partially been offset by lower operating costs.

At Syncrude, operating costs decreased as lower natural gas costs were partially offset by higher maintenance costs. The lower operating costs reduced our corporate average by $0.05/boe.

Depreciation, Depletion, Amortization and Impairment (DD&A)[1]

	2010		2009		2008	
(Cdn$/boe)	Before Royalties[2]	After Royalties	Before Royalties[2]	After Royalties	Before Royalties[2]	After Royalties
Conventional Oil and Gas[3]						
United Kingdom	20.30	20.32	22.42	22.42	17.72	17.72
Canada	20.13	23.05	18.12	21.03	14.99	18.71
United States	25.87	27.80	37.64	42.18	27.46	31.97
Yemen	7.28	13.28	5.75	9.87	7.75	14.45
Other Countries	11.43	12.29	11.16	12.08	7.90	8.58
Average Conventional	18.27	20.69	19.16	22.09	15.48	18.54
Synthetic Crude Oil						
Long Lake	17.99	18.73	–	–	–	–
Syncrude	6.89	7.46	8.46	9.20	6.39	7.35
Average Oil and Gas	17.26	19.38	18.23	20.90	14.71	17.56

1 Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).
2 DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.
3 DD&A per boe excludes the impairment charges described in Note 4 of our Consolidated Financial Statements.

2010 VS 2009— LOWER OIL AND GAS DD&A INCREASED NET INCOME BY $29 MILLION

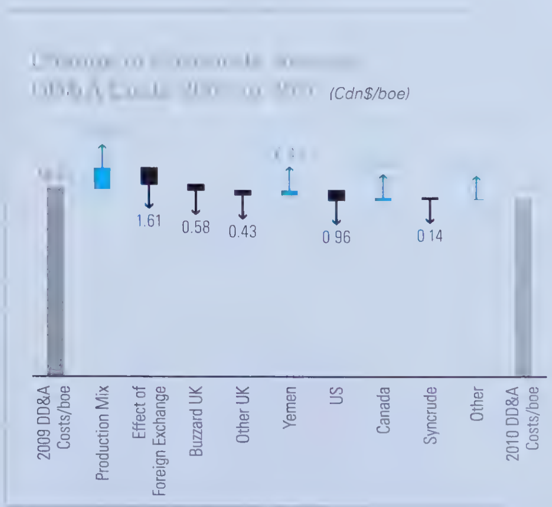
Our average DD&A expense decreased $0.97/boe from last year. The stronger Canadian dollar reduced our corporate average by $1.61/boe as depletion of our international and US assets is denominated in US dollars. This was more than offset by changes in our production mix which increased our corporate average rate by $2.05/boe. The change in mix was mainly driven by higher sales volumes at Ettrick, Longhorn and Long Lake, all of which have depletion rates higher than our corporate average.

At Buzzard, successful drilling last year enabled us to recognize additional proved reserves at the end of 2009. This lowered the field depletion rate for 2010 and reduced our corporate average by $0.58/boe. The remainder of our UK fields reduced our corporate average by $0.43/boe, primarily driven by higher proved reserves at Telford as a result of successful extension drilling of the field.

Higher depletion rates in Yemen increased our corporate average by $0.43/boe. As the fields mature and production declines, our capital is focused on economically recovering the remaining reserves. Our DD&A rates at Syncrude remain low, reducing our corporate average by $0.14/boe.

Our Canadian assets increased our corporate average DD&A rate by $0.26/boe, despite lower DD&A expense with the disposition of heavy oil properties. This increase was driven by higher depletion rates at our CBM and natural gas properties, where low natural gas prices at the end of 2009 reduced reserves. In the US Gulf of Mexico, positive proved reserve revisions at the end of 2009 reduced our corporate average depletion rate by $0.96/boe.

Our DD&A expense in 2010 includes non-cash impairment charges of $93 million on Gulf of Mexico shelf properties. In the third quarter, low natural gas prices triggered an impairment on three small shelf properties. We impaired two additional properties during the fourth quarter where declining production performance and higher estimated future abandonment costs reduced the properties' estimated future cash flows. In each case, the carrying values of the properties were reduced to estimated fair value.



2009 VS 2008—LOWER OIL AND GAS DD&A INCREASED NET INCOME BY $241 MILLION

Our corporate average DD&A cost per barrel in 2009 increased $3.52/boe from 2008. The stronger US dollar increased our corporate average by $1.41/boe as depletion of our international and US assets is denominated in US dollars, while changes in our production profile also increased our corporate average by $0.63/boe. The change in our production mix was primarily a result of: i) slightly lower Buzzard production, where our DD&A rate is low and ii) higher production volumes at Scott/Telford and Ettrick, where we have higher than average DD&A rates. We incurred non-cash impairment charges of $78 million in the fourth quarter of 2009 at three natural gas properties in Canada and the US. Our year-end natural gas proved reserves at these properties were lower as a result of weak natural gas prices.

In the UK North Sea, our Buzzard depletion rate in 2009 decreased from 2008 as successful development drilling increased our proved reserve estimates at the end of 2008. This lower depletion rate reduced our total corporate average by $0.16/boe. Elsewhere in the UK, higher depletion rates at Ettrick and Scott/Telford increased our corporate average by $0.97/boe. The Ettrick depletion rate is higher than our average as a result of higher development costs. The Scott/Telford fields' depletion rate increased compared to 2008 as a result of downward price-related reserve revisions at the end of 2008. Our DD&A expense also includes $49 million for our Perth discovery in the North Sea, where we expensed allocated acquisition costs as we were unlikely to proceed with development of this prospect.

Lower depletion rates in Yemen, due to lower capital expenditures from drilling fewer development wells and higher reserve estimates, reduced our corporate average by $0.61/boe. In the Gulf of Mexico, higher estimates for future abandonment costs and downward price-related reserve revisions at the end of 2008 resulted in higher depletion rates, increasing our corporate average rate by $0.61/boe.

Canadian depletion increased our corporate average by $0.49/boe. Depletion rates at our heavy oil properties increased in 2009 due to downward price-related revisions to our proved reserves at the end of 2008. This was partially offset by lower depletion rates at our CBM properties, where additional proved reserves were recognized through improved recovery rates.

Syncrude incurred an additional depletion expense of $14 million in the fourth quarter of 2009 related to the replacement of an asset that was previously damaged at the upgrading facilities. This increased Syncrude's DD&A rate by $1.95/boe for 2009 and increased our corporate average by $0.18/boe. Excluding the impact of the additional depletion expense, Syncrude's DD&A rate for 2009 was consistent with 2008.

Exploration Expense

(Cdn$ millions)	2010	2009	2008
Seismic	100	81	137
Unsuccessful Drilling	64	115	203
Other	164	106	62
Total Exploration Expense	**328**	**302**	**402**

2010 VS 2009—HIGHER EXPLORATION EXPENSE DECREASED NET INCOME BY $26 MILLION

Our exploration expense increased 9% from 2009. Our exploration program focuses on opportunities in the US Gulf of Mexico, the North Sea and offshore West Africa. Unsuccessful drilling costs were 44% lower than last year and represented 15% of our exploration drilling capital. In 2009, we expensed 26% of our exploration drilling capital. We expensed costs related to three unsuccessful wells in the North Sea and costs related to CBM properties in Canada in 2010. The Brand well and the Deacon well in the North Sea failed to encounter hydrocarbons and we expensed drilling costs of $25 million and $14 million, respectively. In Canada, we expensed $17 million of drilling costs related to our CBM exploration activities in central Alberta, where we have no future development plans.

Seismic expenditures increased 23% compared to 2009. Additional purchases in the Gulf of Mexico and the United Kingdom were partially offset by lower spending in Norway and Canada. Seismic data costs will fluctuate depending on

the level of our evaluation stage. Other exploration costs include support costs, lease rental expenses and unutilized drilling rig costs.

Early in the year, we made a significant oil discovery at Appomattox in the Gulf of Mexico. We subsequently completed two appraisal sidetracks. Further appraisal wells were planned, however, additional drilling has been delayed as a result of the drilling moratorium in the Gulf of Mexico. We anticipate resuming appraisal drilling here in 2011. Appomattox is the third discovery in the area following previous successful drilling at Shiloh and Vicksburg. Our drilling plans also include further appraisal drilling at Vicksburg, located six miles east of Appomattox and has the potential to be co-developed. We have a 25% interest in Vicksburg and a 20% interest in Appomattox and Shiloh, with Shell Offshore Inc. operating all three.

In the UK North Sea, we drilled successful wells at Polecat and West Rochelle, and a successful follow up to our Blackbird discovery.

2009 VS 2008—LOWER EXPLORATION EXPENSE INCREASED NET INCOME BY $100 MILLION

Exploration expenditures in 2009 decreased $56 million from 2008 as we focused our capital on the US Gulf of Mexico, the North Sea and shale gas in Canada. Exploration expense decreased 25% over the same period due to more successful exploration wells in 2009 and lower seismic data acquisition costs.

In the UK, we had significant exploration success in the Golden Eagle area, which includes our operated interest in Golden Eagle, Hobby and Pink. In total, we have drilled three exploration and eleven appraisal wells here.

We drilled a successful exploration well in the southern portion of Oil Prospecting License (OPL) 223, offshore West Africa in 2009. The Owowo South B-1 well was drilled in a water depth of 670 metres and is located 20 kilometres east of the Usan field, currently under development. The well reached a total depth of 2,227 metres and discovered several oil-bearing reservoirs.

In the Gulf of Mexico, drilling operations at Appomattox were ongoing at December 31, 2009. We also completed a successful appraisal well at Knotty Head in 2009, which was drilled by our first contracted deep-water rig, the Ensco 8501.

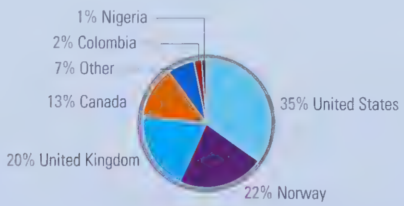
We made significant progress on our shale gas project in the Dilly Creek area of the Horn River Basin in northeast British Columbia. In 2009, we completed a drilling and completion program and realized substantial cost savings and productivity improvements. By the end of 2009, we had five shale gas wells on stream.

Unsuccessful drilling expense in 2009 includes expensing CBM drilling costs in Canada and unsuccessful wells in the Eastern Gulf of Mexico and UK North Sea.

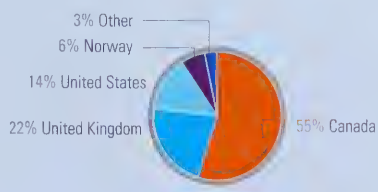
In Canada, we expensed costs of $49 million related to our CBM exploration activities in central Alberta on properties where we had no future development plans. In the Gulf of Mexico, the Antietam well encountered thick, good-quality sand, but was non-commercial and subsequently plugged and abandoned. We expensed costs of $31 million here in 2009. We also chose not to proceed with the development of a small discovery at Green Canyon 448 and accordingly, expensed $14 million of costs.

During 2009, seismic data acquisition costs were $56 million lower than 2008 when we purchased significant seismic data associated with newly acquired blocks in the Norwegian North Sea.

2010 Exploration Expense by Division
($328 million)



2010 Exploration Investment
($957 million)



OIL & GAS NETBACKS

Netbacks are the cash margins we receive for every equivalent barrel sold before general and administrative expenses and cash taxes in the UK. Our netbacks improved 36% since 2006, while WTI and Brent are up 20% and 22%, respectively. Our cash netbacks are 63% of realized sales prices in 2010. This is caused by transitioning our production to lower royalty jurisdictions and stronger commodity prices.

	2010	2009	2008	2007	2006
Oil and Gas Realized Sales Price *(Cdn$/boe)*	70.11	60.02	89.78	68.46	62.92
Cash Netback *(Cdn$/boe)*	44.38	38.55	60.64	43.22	32.75
Cash Netback as % of Realized Sales Price	63%	64%	68%	63%	52%

The following table includes the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

Before Royalties[1]

	2010							
(Cdn$/boe)	**UK**	**Canada**	**Long Lake**	**Syncrude**	**US**	**Yemen**	**Other**	**Total**
Sales	76.51	34.33	77.07	81.23	47.35	81.86	76.83	70.11
Royalties and Other	–	(5.29)	(3.65)	(6.27)	(3.55)	(36.65)	(5.37)	(8.16)
Operating Expenses	(8.24)	(12.31)	(100.09)	(36.74)	(10.02)	(10.25)	(6.99)	(15.67)
In-country Taxes[2]	–	–	–	–	–	(10.80)	–	(1.90)
Cash Netback	**68.27**	**16.73**	**(26.67)**	**38.22**	**33.78**	**24.16**	**64.47**	**44.38**

	2009							
(Cdn$/boe)	**UK**	**Canada**	**Long Lake**	**Syncrude**	**US**	**Yemen**	**Other**	**Total**
Sales	65.93	34.58	–	70.96	46.27	68.49	59.05	60.02
Royalties and Other	–	(5.75)	–	(6.04)	(4.89)	(28.94)	(4.52)	(8.06)
Operating Expenses	(6.87)	(12.76)	–	(35.92)	(12.58)	(10.69)	(6.03)	(11.66)
In-country Taxes[2]	–	–	–	–	–	(8.31)	–	(1.75)
Cash Netback	**59.06**	**16.07**	**–**	**29.00**	**28.80**	**20.55**	**48.50**	**38.55**

	2008							
(Cdn$/boe)	**UK**	**Canada**	**Long Lake**	**Syncrude**	**US**	**Yemen**	**Other**	**Total**
Sales	94.45	58.34	–	105.47	79.02	99.87	98.98	89.78
Royalties and Other	–	(12.25)	–	(15.11)	(11.03)	(46.94)	(7.88)	(15.06)
Operating Expenses	(6.75)	(13.12)	–	(36.53)	(11.57)	(8.51)	(4.52)	(11.04)
In-country Taxes[2]	–	–	–	–	–	(13.31)	–	(3.04)
Cash Netback	**87.70**	**32.97**	**–**	**53.83**	**56.42**	**31.11**	**86.58**	**60.64**

After Royalties[1]

(Cdn$/boe)	UK	Canada	Long Lake	Syncrude 2010	US	Yemen	Other	Total
Sales	76.51	34.33	77.07	81.23	47.35	81.86	76.83	70.11
Operating Expenses	(8.24)	(14.10)	(105.17)	(39.78)	(10.76)	(18.69)	(7.52)	(17.62)
In-country Taxes[2]	–	–	–	–	–	(19.69)	–	(2.15)
Cash Netback	**68.27**	**20.23**	**(28.10)**	**41.45**	**36.59**	**43.48**	**69.31**	**50.34**

(Cdn$/boe)	UK	Canada	Long Lake	Syncrude 2009	US	Yemen	Other	Total
Sales	65.93	34.58	–	70.96	46.27	68.49	59.05	60.02
Operating Expenses	(6.87)	(14.80)	–	(39.09)	(14.10)	(18.34)	(6.53)	(13.33)
In-country Taxes[2]	–	–	–	–	–	(14.26)	–	(2.00)
Cash Netback	**59.06**	**19.78**	**–**	**31.87**	**32.17**	**35.89**	**52.52**	**44.69**

(Cdn$/boe)	UK	Canada	Long Lake	Syncrude 2008	US	Yemen	Other	Total
Sales	94.45	58.34	–	105.47	79.02	99.87	98.98	89.78
Operating Expenses	(6.75)	(16.38)	–	(42.04)	(13.48)	(15.88)	(4.91)	(13.18)
In-country Taxes[2]	–	–	–	–	–	(24.83)	–	(3.63)
Cash Netback	**87.70**	**41.96**	**–**	**63.43**	**65.54**	**59.16**	**94.07**	**72.97**

1 Before-royalty cash netbacks are calculated by dividing sales, royalties and other, operating expenses and in-country taxes by production before royalties. After-royalty cash netbacks are calculated by dividing sales, operating expenses and in-country taxes by production after royalties.

2 Comprises income taxes payable in Yemen that are included in the government's share of profit oil.

ENERGY MARKETING

(Cdn$ millions)	2010	2009	2008
Contribution to Net Marketing Revenue by Region			
North America	21	318	(284)
International	5	30	27
Net Marketing Revenue[1]	**26**	**348**	**(257)**
Depreciation, Depletion, Amortization and Impairment	(18)	(27)	(19)
General and Administrative	(69)	(91)	(79)
Net Loss on Dispositions	(103)	–	–
Allowance for Doubtful Receivables	–	5	(54)
Marketing Contribution to Income before Income Taxes	**(164)**	**235**	**(409)**
Physical Sales Volumes[2]			
North America Crude Oil *(mbbls/d)*	747	827	656
International Crude Oil *(mbbls/d)*	77	94	99
North America Natural Gas *(bcf/d)*	2.8	3.1	6.7
Value-at-Risk			
Year End	11	11	25
High	15	24	40
Low	4	9	19
Average	10	15	30

1 Net Marketing Revenue includes net sales, marketing and other revenue, operating, transportation and other expenses in the Consolidated Statement of Income.

2 Excludes inter-segment transactions. Physical volumes represent amounts delivered during the year.

2010 VS 2009—LOWER CONTRIBUTIONS FROM ENERGY MARKETING REDUCED NET INCOME BY $322 MILLION

Energy marketing generated $224 million of proceeds in 2010 from dispositions including the sale of our European gas and power business, our North America natural gas trading operations and our crude oil lease gathering, pipeline and storage assets in North Dakota and Montana, thereby substantially completing the re-alignment of our energy marketing business to focus on marketing proprietary crude oil production from North America, the North Sea and Yemen.

Results from energy marketing for the year are lower compared to last year when our marketing contribution was bouyed by the increased value of our natural gas inventories with rising gas prices in late 2009. Gains generated during the fourth quarter of 2010 from capturing crude oil contango (increasing future prices) were offset by widening heavy oil differentials in 2010.

Our North America crude oil team generated positive results in 2010 from blending activities and capturing contango in the forward price curve, offset somewhat by losses from widening differentials. In 2009, we generated strong results due to steep contango early in the year while 2010 saw modest gains from contango. Losses from widening differentials, particularly late in 2010, are primarily due to reduced capacity on pipelines as a result of apportionment in North America and the consequential challenges to flow product. Due to our strong relationships and access to infrastructure, we did not shut in production from our proprietary crude oil operations during the apportionment in 2010.

Our North America natural gas business recognized gains in late 2009 as a result of unrealized gains on inventory carried at fair value and gains on derivatives used to hedge our transportation capacity. In 2010, losses were generated early in the year from declining spot prices on inventory and narrowing transportation spreads between producing and consuming regions, which impacted our ability to generate profits.

After achieving strong results in 2009, our international crude oil team generated modest gains in 2010 primarily as a result of increased competition from crudes similar to Masila.

2009 VS 2008—HIGHER CONTRIBUTIONS FROM ENERGY MARKETING INCREASED NET INCOME BY $605 MILLION

Energy marketing generated $348 million in net revenue in 2009, with all businesses contributing positive results.

During the fourth quarter of 2009, energy marketing continued to optimize trading around physical assets, resulting in gains on physical positions and commodity inventory, together with gains from blending in our crude oil business. During the latter part of 2009, gas prices increased as a result of cold weather across North America creating unrealized gains on inventory, which is carried at fair value. We also recognized gains on derivatives used to hedge our transportation capacity.

The largest contribution in 2009 came from our global crude oil business, which generated gains by inventory management and physical business as a result of contango in the forward price curve. These gains were recognized largely in the first quarter of 2009. This contango, combined with narrowing crude oil differentials, enabled us to capture both realized and unrealized gains on our relatively low-risk physical trading strategies.

Similar to 2008, the natural gas business faced a challenging economic environment in 2009. Gas prices remained suppressed while location spreads between markets continued to narrow throughout the year. Early in 2009, the gas business incurred losses as a result of exiting the last of its trading positions from 2008 and from selling natural gas inventory where the offsetting gains on the financial instruments hedging the inventory were recognized in prior periods. Weakness in gas markets reduced the value of holding transportation capacity. Any losses associated with the transportation and storage capacity contracts will be recognized when the contracts are used or sold.

COMPOSITION OF NET MARKETING REVENUE

(Cdn$ millions)	2010	2009	2008
Trading Activities (Physical and Financial)	14	339	(287)
Other Activities	12	9	30
Total Net Marketing Revenue	**26**	**348**	**(257)**

TRADING ACTIVITIES

In our energy marketing group, we enter into contracts to purchase and sell energy commodities (now primarily crude oil). We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes. In 2010, we substantially completed the re–alignment of our energy marketing business to focus on marketing proprietary crude oil, which reduced our use of financial and derivative contracts. We account for all derivative contracts using fair value accounting and record the net gain or loss from their revaluation in marketing and other income.

OTHER ACTIVITIES

We enter into fee-for-service contracts related to transportation and storage of third-party oil and gas. In addition, we earn income from our power generation facilities at Balzac and Soderglen.

FAIR VALUE OF DERIVATIVE CONTRACTS

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange (formerly Netthruput), independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

At December 31, 2010, the fair value of our derivative contracts used in our energy marketing trading activities totaled $(18) million. Below is a breakdown of the derivative fair value by valuation method and contract maturity:

	Maturity				
(Cdn$ millions)	**< 1 year**	**1–3 years**	**4–5 years**	**> 5 years**	**Total**
Level 1—Actively Quoted Markets	(17)	–	–	–	(17)
Level 2—Based on Other Observable Pricing Inputs	(11)	(7)	–	–	(18)
Level 3—Based on Unobservable Pricing Inputs	9	8	–	–	17
Fair Value at December 31, 2010	**(19)**	**1**	**–**	**–**	**(18)**

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	**Total**
Fair Value at December 31, 2009	23
Change in Fair Value of Contracts	(2)
Net Losses (Gains) on Contracts Sold	19
Net Losses (Gains) on Contracts Closed	(58)
Changes in Valuation Techniques and Assumptions[1]	–
Fair Value at December 31, 2010	**(18)**

1 *Our valuation methodology has been applied consistently each period.*

The fair values of our derivative contracts will be realized over time as the related contracts settle. Until then, the value of certain contracts will vary with forward commodity prices and price differentials.

CHEMICALS

(Cdn$ millions)	**2010**	**2009**	**2008**
Net Sales	456	458	477
Sales Volumes (thousand short tons)			
Sodium Chlorate	476	441	495
Chlor-alkali	492	447	469
Operating Profit[1]	97	143	125
Operating Margin[2]	21%	31%	26%
Chemicals Contribution to Income Before Income Taxes[3]	18	79	(14)
Capacity Utilization	84%	88%	92%

1 *Net sales less operating costs, transportation and other expenses.*
2 *Operating profit divided by net sales.*
3 *Includes foreign exchange gains and losses on long-term debt.*

2010 VS 2009—LOWER CHEMICALS CONTRIBUTION DECREASED NET INCOME BY $48 MILLION

North America chlorate revenue decreased 2% in 2010, as an 11% decrease in prices was partially offset by a 10% increase in sales volumes. North America chlor-alkali revenue remained flat as weaker caustic prices were offset by higher volumes. In Brazil, sales revenues increased by 2% as strong chlorate revenues were partially offset by lower acid revenues. Chlorate revenues increased by 4% as a result of higher prices. This was partially offset by lower acid revenues of 10% as a result of lower prices and sales volumes.

The Canadian dollar continued to strengthen during the year and chemicals contribution includes foreign exchange gains of $15 million on the Canexus US-dollar denominated debt. The 2009 results included unrealized foreign exchange gains of $50 million related to Canexus US-dollar denominated debt.

In early 2011, we sold our remaining interest in these chemical operations for $458 million of cash proceeds and we have no continuing involvement in the business after February 7, 2011. We expect to recognize a gain of approximately $250 to $300 million in the first quarter of 2011. Since 2005 when we completed the initial public offering of our chemicals business through Canexus, we have realized proceeds of approximately $900 million (including cash distributions).

2009 VS 2008—HIGHER CHEMICALS CONTRIBUTION INCREASED NET INCOME BY $73 MILLION

North America chlorate revenue decreased 2% from 2008, as a 13% reduction in sales volumes attributable to the global economic downturn was partially offset by stronger pricing. North America chlor-alkali revenue increased 2% from 2008 as weaker caustic prices somewhat offset higher volumes. In Brazil, lower caustic prices and a decline in sales volumes decreased chlor-alkali revenues 32%. Chlor-alkali sales volumes decreased because we reduced sales of purchased product as this activity generates no gross margin. There was no impact on our returns in Brazil by eliminating this activity. Chlorate sales in Brazil increased 5% from the prior year as a result of higher prices.

The Canadian dollar strengthened in 2009 and chemicals contribution includes unrealized foreign exchange gains of $50 million on the Canexus US-dollar denominated debt. This compared to our 2008 results, which included unrealized foreign exchange losses of $54 million.

CORPORATE EXPENSES

General and Administrative (G&A)[1]

(Cdn$ millions)	2010	2009	2008
General and Administrative Expense before Stock-Based Compensation	496	428	417
Stock-Based Compensation[2]	(14)	69	(160)
Total	**482**	**497**	**257**

1 Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).
2 Includes cash and non-cash expenses related to our tandem option plan, stock appreciation rights plan and restricted share unit plan.

2010 VS 2009—LOWER COSTS INCREASED NET INCOME BY $15 MILLION

G&A costs decreased 3% from 2009 primarily as the impact of a recovery of stock-based compensation during the year was substantially offset by higher G&A costs. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation obligations and related expense. During the year, we recovered non-cash stock-based compensation costs of $41 million as our stock price ended the year at $22.80/share, compared to the previous year when it closed at $25.22/share. This recovery was partially offset by cash payments for stock-based compensation programs of $27 million, 66% lower than last year.

G&A expenses before stock-based compensation increased $68 million primarily due to non-recurring costs associated with our non-core asset disposition programs.

2009 VS 2008—HIGHER COSTS DECREASED NET INCOME BY $240 MILLION

Higher stock-based compensation expense was the primary reason for the 93% increase in G&A costs in 2009. Changes in our share price create volatility in our net income as we account for stock-based compensation using the intrinsic-value method. This method uses our share price at the end of the reporting period to determine our stock-based compensation obligations and related expense. Our stock price fluctuated during the year before closing at $25.22/share, up 18% from $21.45/share at the end of 2008. Cash payments made in connection with our stock-based compensation programs in 2009 decreased 29% from 2008 to $79 million. Cash payments were higher in 2008 as our stock price reached a high of $43.45/share during the year.

Interest [1]

(Cdn$ millions)	2010	2009	2008
Interest	411	389	334
Less: Capitalized	(87)	(77)	(240)
Net Interest Expense	**324**	**312**	**94**
Effective Interest Rate	5.8%	5.0%	5.9%

1 *Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).*

2010 VS 2009—HIGHER NET INTEREST EXPENSE REDUCED NET INCOME BY $12 MILLION

Net financing costs increased $12 million from last year as higher interest costs of $22 million were partially offset by additional capitalized interest of $10 million. The higher expense was due to additional borrowing costs of $52 million on our long-term debt and additional stand-by fees of $8 million on our term credit facilities. These costs were reduced by the impact of a stronger Canadian dollar, which lowered our US-dollar denominated interest costs by $41 million.

Capitalized interest was $10 million higher than last year. Increases in capitalized interest at Usan and on the fourth platform at Buzzard, were partially offset by lower capitalized interest on Ettrick, which was completed in the prior year.

2009 VS 2008—HIGHER NET INTEREST EXPENSE REDUCED NET INCOME BY $218 MILLION

Financing costs increased $55 million from 2008. This 16% increase was a result of higher levels of debt, partially offset by lower interest rates. Our capital investment program, including the acquisition of an additional 15% interest in Long Lake, exceeded our cash flow, causing us to draw upon of our term credit facility. In addition, we issued US$1 billion of long-term notes in the third quarter of 2009, increasing interest costs by $32 million this year. The stronger US dollar increased our US-dollar denominated interest costs for the year by $32 million.

During 2009, capitalized interest decreased $163 million from 2008 as a result of completing major development projects. Long Lake capitalized interest in 2009 was $23 million, down $183 million from 2008, while Ettrick capitalized interest decreased $7 million during the year. This was partially offset by an increase in Usan capitalized interest of $16 million. In addition to our Usan development, we capitalized interest on the construction of the fourth platform at Buzzard and our Chemicals technology conversion project in North Vancouver.

Income Taxes [1]

(Cdn$ millions)	2010	2009	2008
Current	1,132	776	859
Future	(368)	(516)	598
Total Provision for Income Taxes	**764**	**260**	**1,457**

1 *Includes results of discontinued operations (see Note 20 of our Consolidated Financial Statements).*

2010 VS 2009—HIGHER TAXES DECREASED NET INCOME BY $504 MILLION

Our total provision for income taxes increased from 2009 as a result of net gains on our non-core asset disposition program and stronger commodity prices, which improved our operating results. Our income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

2009 VS 2008—LOWER TAXES INCREASED NET INCOME BY $1,197 MILLION

Our provision for income taxes decreased by $1,197 million as compared to the prior year. Lower commodity prices and production, a reduction in Canadian tax rates and a fair value unrealized loss on our crude oil put options contributed to lower tax expense in 2009. During the year, future tax expense was reduced by amortizing the deferred tax credit arising from the internal reorganization and financing of our North Sea assets completed in 2008. Our income tax provision includes current taxes in the United Kingdom, Yemen, Norway, Colombia and the United States.

Other

(Cdn$ millions)	**2010**	**2009**	**2008**
Non-core Asset Disposition Net Gains	740	–	–
Increase (Decrease) in Fair Value of Crude Oil Put Options	(41)	(251)	203

In 2010, we realized net gains of $740 million on the disposition of non-core assets, consisting of the following:

- heavy oil properties in Canada for proceeds of $939 million, net of closing adjustments, realizing a gain of $781 million;
- North American natural gas energy marketing operations for proceeds of $9 million, recognizing a non-cash loss of $259 million, which were primarily related to the transfer of long–term physical transportation commitments;
- crude oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of $201 million, realizing a gain of $121 million;
- lands in the Athabasca region of Northern Alberta for which we had no near-term development plans for proceeds of $81 million, realizing a gain of $80 million; and
- undeveloped lease in the UK North Sea for proceeds and gains of $17 million.

In 2010, we purchased put options on 100,000 bbls/d of our 2011 crude oil production. These options establish a monthly WTI floor price of between US$50/bbl and US$63/bbl and provide a base level of price protection without limiting our upside to higher prices. The options settle monthly and are recorded at fair value throughout their term. As a result, changes in forward crude oil prices created gains or losses on these options at each period end. The put options were purchased for $33 million and are carried at fair value. At December 31, 2010, the fair value of the options was approximately $9 million and we recorded a fair value loss of $24 million in the year.

In late 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options established a WTI floor price of US$50/bbl on these volumes. Options on 60,000 bbls/d settled monthly, while the remaining options settled annually. The put options were purchased for $39 million and were carried at fair value. At December 31, 2009, higher crude oil prices reduced the fair value of the options to $17 million, and we recorded a fair value loss in 2009 of $22 million. At December 31, 2010, higher forward crude oil prices reduced the fair value of the options to nil and we expensed the remaining fair value of $17 million in 2010.

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options were purchased for $14 million and established an annual Dated Brent floor price of US$60/bbl on these volumes. At December 31, 2008, the put options had an estimated fair value of $233 million due to significantly lower crude oil prices. Strengthening crude oil prices in 2009 reduced the fair value of these options to nil and we recorded a fair value loss of $229 million in 2009.

SUMMARY OF QUARTERLY RESULTS

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	2010	2009	2010	2009	2010	2009	2010	2009
Net Sales from Continuing Operations	1,319	880	1,294	1,029	1,298	919	1,500	1,375
Income (Loss) from Continuing Operations before Income Taxes is Comprised of:								
Oil and Gas	487	219	588	286	376	250	476	447
Energy Marketing[1]	(67)	83	(5)	25	(240)	18	113	109
Corporate and Other	(107)	(120)	(149)	(323)	(163)	(66)	(183)	(170)
	313	**182**	**434**	**(12)**	**(27)**	**202**	**406**	**386**
Net Income (Loss) from Continuing Operations	**163**	**147**	**250**	**14**	**(59)**	**102**	**218**	**249**
Net Income	**185**	**135**	**255**	**20**	**537**	**122**	**220**	**259**
Earnings (Loss) per Common Share from Continuing Operations *($/share)*								
Canadian GAAP—Basic	0.31	0.28	0.48	0.03	(0.11)	0.20	0.41	0.48
Canadian GAAP—Diluted	0.31	0.26	0.47	0.00	(0.11)	0.17	0.41	0.47
Earnings per Common Share *($/share)*								
Canadian GAAP—Basic	0.35	0.26	0.49	0.04	1.02	0.23	0.42	0.50
Canadian GAAP—Diluted	0.35	0.24	0.48	0.01	1.02	0.21	0.42	0.49
Dividends Declared	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Common Share Prices *($/share)*								
Toronto Stock Exchange—High	25.91	24.24	26.91	28.54	22.33	25.94	23.00	27.31
Toronto Stock Exchange—Low	22.38	14.86	20.92	20.65	18.33	20.70	20.57	22.26
New York Stock Exchange—High *(US$)*	24.98	20.61	26.92	26.25	21.54	24.43	23.01	26.05
New York Stock Exchange—Low *(US$)*	21.06	11.89	19.66	16.33	17.20	18.68	20.12	20.66

1 *The third quarter of 2010 includes asset disposition losses of $259 million and the fourth quarter includes asset disposition gains of $121 million (see Note 18 of our Consolidated Financial Statements).*

In 2010, we substantially completed the realignment of our energy marketing business to focus on marketing proprietary crude oil. As a result, our results in the third quarter includes asset disposition losses of $259 million and our fourth quarter results includes asset disposition gains of $121 million (see Note 18 of our Consolidated Financial Statements).

Quarterly variances in net sales and earnings are largely driven by fluctuations in commodity prices and changes in production volumes due to: the temporary shutdown of facilities for maintenance, natural declines of mature fields and the ramp-up of new producing fields. In addition, disposition net gains of $740 million were realized in 2010 as a result of our successful non-core asset disposition program, of which $781 million relating to our Canadian heavy oil disposition is included in discontinued operations (see notes 18 and 20 to our Consolidated Financial Statements).

Capital Investment

In 2011, we plan to invest between $2.4 and $2.7 billion in our oil and gas operations to advance our strategies as follows:

- $1.5 to $1.6 billion on the development of Usan, offshore West Africa, development of the Golden Eagle area in the North Sea, a joint development plan to move Knotty Head in the Gulf of Mexico towards sanctioning, and on exploration and appraisal opportunities in the North Sea, Gulf of Mexico, Canada and Colombia;
- $550 to $600 million on the oil sands as we focus on Long Lake, advancing our Kinosis project and at Syncrude; and
- $300 to $350 million on our drilling and completion programs at our Horn River shale gas play.

Details of our 2011 capital program are included in the Capital Investment section of this MD&A.

Production

For 2011, we expect our annual production will range between 230,000 and 270,000 boe/d (210,000 to 240,000 boe/d after royalties). The range is driven by the pace of ramp–up at Long Lake, run-times at Buzzard and Scott/Telford in the North Sea and our Horn River shale gas program. We expect to grow production after royalties by approximately 4% assuming the midpoint of our guidance range and 7% after adjusting for the sale of our heavy oil properties in 2010.

	2011 Estimated Production		**2010 Production**	
(mboe/d)	**Before Royalties**	**After Royalties**	**Before Royalties**	**After Royalties**
United Kingdom	110-130	110-130	111	111
Canada	18-26	16-23	28	25
Long Lake Bitumen	25-29	22-26	16	15
Syncrude	20-24	18-22	21	19
United States	20-28	17-24	27	25
Yemen	28-35	16-20	41	23
Other Countries	2-3	2-3	2	2
Total	**230-270**	**210-240**	**246**	**220**

Cash Flow and Sensitivities

We expect cash flow from operations will range from $2.1 to $2.8 billion in 2011, assuming the following:

	Low	High
WTI (US$/bbl)	$75	$90
NYMEX Natural Gas (US$/mmbtu)	$4.00	$5.50
US to Canadian Dollar Exchange Rate	$1.00	$1.00

Changes in commodity prices and exchange rates impact our annual cash flow from operating activities, after cash taxes, as follows:

(Cdn$ millions)	
WTI—US$1/bbl change above US$56	42
WTI—US$1/bbl change below US$56 [1]	21
NYMEX Natural Gas—US$0.50/mcf change	18
Exchange Rate—$0.01 US/Cdn change	26

1 *Our put option program for 2011 mitigates the impact of a price decline below approximately US$56 WTI.*

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	December 31, 2010	December 31, 2009
Net Debt[1]		
Bank Debt	–	1,803
Public Senior Notes	4,636	4,982
Total Senior Debt	**4,636**	**6,785**
Subordinated Debt	443	466
Total Debt	**5,079**	**7,251**
Less: Cash and Cash Equivalents	(1,005)	(1,700)
Total Net Debt[2]	**4,074**	**5,551**
Nexen Inc. Shareholders' Equity[3]	**8,707**	**7,582**

1 *Includes all of our debt and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.*

2 *December 31, 2010 excludes Net Debt related to our chemical operations that is included in assets and liabilities held for sale (see Note 20 of our Consolidated Financial Statements). Our remaining interest was sold in February 2011 for $458 million.*

3 *Equity is the historical issue price of equity and accumulated retained earnings.*

Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows and capital investment. We ended the year with net debt of approximately $4,074 million, $1,477 million lower than 2009. The year-over-year change in our net debt results from:

(Cdn$ millions)	2010	2009
Capital Investment	2,523	2,742
Proved Property Acquisitions	79	755
Net Proceeds from Non-core Asset Dispositions	(1,262)	(17)
Cash Flow from Operating Activities	(2,349)	(1,886)
Deficiency (Surplus)	(1,009)	1,594
Dividends on Common Shares	104	104
Issue of Common Shares	(55)	(57)
Reclassification of Canexus Net Debt Related to Sale	(391)	–
Other	77	232
Foreign Exchange Translation of US-dollar Debt and Cash	(203)	(897)
Increase (Decrease) in Net Debt	**(1,477)**	**976**

Our net debt decreased 27% from last year primarily as a result of our non-core asset disposition program. Our 2010 disposition program included the sale of our heavy oil assets in Canada and the sale of various non-core energy marketing operations. Total proceeds from our disposition program in 2010 was approximately $1.3 billion. In early 2011, we generated additional proceeds of $458 million from the sale of our interest in Canexus. Net debt related to Canexus of $391 million has been included in liabilities held for sale at December 31, 2010.

Our capital investment continues to focus on our three key growth areas of conventional exploration and development, oil sands and unconventional gas. In 2010, our capital investment and property acquisition costs were approximately $900 million lower than the previous year, when we acquired our additional 15% interest in Long Lake. Cash flow from operating activities increased from 2009 as a result of higher production and stronger commodity prices. Our oil and gas investment exceeded our operating cash flows by about $250 million in 2010, largely due to the acquisition of acreage in the Horn River shale gas play. The stronger Canadian dollar relative to the US dollar reduced our US-dollar-denominated debt. We currently have liquidity of approximately $4 billion, which is comprised of cash and undrawn committed credit facilities, most of which are available until July 2014.

Operating cash flows in the oil and gas industry can be volatile as short-term commodity prices are driven by existing supply and demand fundamentals and market volatility. We manage our investments through the lows of the commodity cycle to create future growth and value for our shareholders over the long term without putting our balance sheet under undue financial risk.

The change in our net debt, combined with higher cash flow and earnings, reduced our leverage in 2010 as reflected in the following ratios:

(times)	**2010**	**2009**	**2008**
Net Debt to Cash Flow from Operating Activities[1]	1.9	2.5	1.1
Interest Coverage[2]	9.3	8.5	15.6

1 *For purposes of this calculation, cash flow from operating activities is before changes in non-cash working capital and other.*
2 *Earnings before interest, taxes, DD&A, exploration and other non-cash expenses, divided by interest expense (before capitalized interest).*

For the 12 months ended December 31, 2010, our net debt to cash flow from operating activities (before changes in non-cash working capital and other) ratio was 1.9 times (WTI average of US$79.52) compared to 2.5 times at December 31, 2009 (WTI average of US$61.80). On a pro forma basis adjusted for the sale of Canexus it would be 1.7 times, whereas using WTI US$96 experienced in 2008, our ratio would be 1.1 times. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility, where we are in our investment cycle or when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Change in Working Capital

(Cdn$ millions)	**December 31 2010**	**December 31 2009**	**Increase (Decrease)**
Cash and Cash Equivalents	1,005	1,700	(695)
Restricted Cash	40	198	(158)
Accounts Receivable	1,938	2,788	(850)
Inventories and Supplies	549	680	(131)
Accounts Payable and Accrued Liabilities	(2,545)	(3,038)	493
Other	33	70	(37)
Total	**1,020**	**2,398**	**(1,378)**

Our working capital balances decreased significantly from last year. Cash and cash equivalents decreased $695 million as we used proceeds from the disposition program and cash on hand to fund our capital investment shortfall and repay our term credit facilities during the year. Accounts receivable, inventory and accounts payable reduced as a result of changes in our energy marketing group and the disposition of our heavy oil properties in Canada. The sale of our North American natural gas operations included the transfer of inventory, accounts receivable and payable balances to the purchaser. This, combined with reduced trading activity as we focus on supporting our core physical business as a producer/marketer, reduced our energy marketing working capital requirements from 2009.

Our working capital balances at December 31, 2010 exclude accounts receivable, inventories and accounts payable related to our chemicals operations as these balances are included in assets and liabilities held for sale.

At December 31, 2010, our restricted cash consists of margin deposits of $40 million (2009—$198 million) related to exchange-traded derivative financial contracts used by our energy marketing group to economically hedge physical commodities, storage, transportation and customer sales contracts. We are required to maintain margin for net out-of-the-money derivative financial contracts.

The weaker US dollar at the end of the year impacted our US-dollar denominated working capital by decreasing accounts receivable, inventories and accounts payable by approximately $123 million, $19 million and $123 million, respectively.

Liquidity

We generally rely on operating cash flows to fund capital requirements over time and provide liquidity. Given the long cycle-time of some of our development projects and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow in any given year. We also require liquidity for our energy marketing business. We believe that maintaining strong liquidity is critical during periods of uncertain economic markets. We currently have liquidity of approximately $4 billion, comprised of cash and undrawn committed credit facilities.

We maintain significant committed and unsecured credit facilities. At December 31, 2010, we had term credit facilities of $3 billion that are available until July 2014, of which $322 million was utilized to support letters of credit. We also had $464 million of uncommitted, unsecured credit facilities, of which $112 million was supporting letters of credit outstanding at December 31, 2010.

From time to time, we access capital markets to meet our financing needs. We also use financial instruments to minimize exposure to fluctuating commodity prices and foreign exchange. For example, we routinely purchase WTI and Dated Brent put options to establish a minimum value for our production. We manage our capital structure to maintain flexibility so we can fund our capital programs given the cyclical nature of the oil and gas business.

The following table shows how we financed our business activities over the last five years. When our operating cash flows exceed our investment requirements, we generally pay down debt or return cash to shareholders. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn$ millions)	**2010**	**2009**	**2008**	**2007**	**2006**
Cash Flow from Operating Activities	2,349	1,886	4,354	2,830	2,374
Cash Flow from Investing Activities	(1,422)	(3,743)	(3,189)	(3,281)	(3,388)
Surplus (Deficiency)	927	(1,857)	1,165	(451)	(1,014)
Cash Flow from Financing Activities	(1,506)	1,821	322	677	1,081
Net Cash Generated (Used)	**(579)**	**(36)**	**1,487**	**226**	**67**

In 2006, we borrowed approximately $1 billion under our committed term credit facilities and used cash flow from operating activities to fund our capital program. In 2007, we issued US$1.5 billion in senior debt to repay outstanding term credit facilities and $150 million in medium-term notes, as well as to fund our 2007 capital program.

In 2008, our cash flow from operating activities exceeded capital expenditures by approximately $1.3 billion and we used this excess to: i) build our cash balances; ii) repay debt including maturing medium term notes of $125 million; and iii) repurchase approximately 12 million common shares at a cost of $338 million.

In 2009, our capital investment, including the acquisition of an additional working interest in Long Lake, exceeded our cash flow from operating activities. The purchase of Long Lake was funded primarily from accumulating excess cash in 2008. In response to improving credit markets, we also issued US$1 billion of senior notes during the year, with US$300 million maturing in 2019 and US$700 million maturing in 2039. Proceeds from the debt issue were used to repay a portion of our outstanding term credit facilities as well as for general corporate purposes.

In 2010, we repaid $1.5 billion of term credit facilities using proceeds from our non-core asset disposition program. Repaying our outstanding term credit facilities increased the average term-to-maturity of our debt to 21 years.

Our marketing business also requires liquidity to support its activities. We require liquidity for working capital and cash or credit lines to fund collateral requirements and to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to

effectively manage credit risk. These agreements can require collateral to be posted if adverse credit-related events, such as reduced credit rating to non-investment grade, occur. We have developed mitigation strategies to significantly reduce our overall exposure if such a downgrade were to occur. We believe our current liquidity is sufficient to fund this exposure, if necessary. Additionally, our exchange-traded contracts require that we provide margin based on daily fluctuations in the value of our contracts. The largest single-day margin call we received during 2010 was $13 million. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required if our credit ratings were reduced.

Future Liquidity

Our future liquidity depends upon cash flow generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Our 2011 capital investment budget is approximately $2.4 to $2.7 billion, and our cash flow from operations is expected to be $2.1 to $2.8 billion at WTI of US$75 to US$90. We continue to monitor economic conditions and commodity prices and will adjust our capital investment program accordingly.

Changes in commodity prices and exchange rates will impact our cash flow and borrowing requirements. Refer to the Outlook for 2011 section on page 97 to see how changes in the above assumptions can impact our cash flow.

At December 31, 2010, we had $1 billion in cash, US$3 billion of undrawn committed credit facilities and $464 million of undrawn uncommitted credit facilities. The only debt maturity of significance in the next few years is our US$500 million notes, which mature in November 2013. Given the long term-to-maturity of a significant portion of our debt, we believe we are well positioned to bring our development projects to production and pursue our next generation of growth while preserving our liquidity.

Our debt maturities over the next five years are:

(Cdn$ millions)	2011	2012	2013	2014	2015
Term Credit Facilities[1]	–	–	–	–	–
Long-Term Notes	–	–	497	–	249
Total[2]	**–**	**–**	**497**	**–**	**249**

1 US$3 billion available until July 2014.
2 Excludes debt related to our chemical operations that are included in liabilities held for sale (see Note 20 of our Consolidated Financial Statements).

For the past several years, we invested significant capital in a number of major development projects, including Buzzard, Long Lake, Ettrick and Usan. The large capital investment required in these projects is substantially behind us and we expect these assets will make significant contributions to our future cash flows. Cash flows generated from these projects allow us to repay debt and invest in our next generation of new growth projects, such as: i) Usan, offshore West Africa; ii) shale gas in the Horn River Basin; and iii) the Golden Eagle area in the UK North Sea. In 2011, we expect to invest $500 million to progress our Usan development, $350 million at Horn River and $150 million at Golden Eagle. We maintain significant undrawn committed credit facilities to manage these risks. We also have a US$3.5 billion shelf prospectus filed in the US and Canada for sales of debt securities and common shares, under which we issued US$1 billion of debt securities in July 2009. This shelf prospectus is due to expire in July 2011.

We are well positioned with our current debt structure. Our only debt covenant requires us to maintain a debt to EBITDA ratio of less than 3.5. At December 31, 2010, this ratio was approximately 1.3 times. We do not expect to exceed 3.5 based on our current debt levels and planned operations.

With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets, and flexibility to reduce future capital expenditure programs, we expect to be able to fund all planned capital, dividend distributions and debt repayments and meet other obligations that may arise from our oil and gas and energy marketing operations.

In 2010 and 2009, the Board declared common share dividends of $0.20. In 2008, the Board declared common share dividends of $0.175.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements can require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. We have significant undrawn credit facilities and cash to fund these potential collateral requirements. Just as we may be required to post collateral in the case of an adverse credit–related event, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral for amounts they owe us in similar circumstances.

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

		Payments			
(Cdn$ millions)	**Total**	**< 1 year**	**1–3 years**	**4–5 years**	**> 5 years**
Long-Term Debt	5,171	–	497	249	4,425
Cumulative Interest on Long-Term Debt	7,286	336	670	612	5,668
Operating Leases[1]	423	98	163	84	78
Capital Leases	86	4	8	8	66
Energy Commodity Contracts	283	168	105	5	5
Transportation and Storage Commitments[1]	435	134	196	75	30
Work Commitments and Purchase Obligations[2]	1,735	961	654	75	45
Asset Retirement Obligations	2,552	55	84	145	2,268
Total	**17,971**	**1,756**	**2,377**	**1,253**	**12,585**

1 Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.
2 Some of these payments relate to work commitments that we can cancel without penalties or additional fees.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur. With respect to information in the table above:

- Short-term and long-term debt amounts are included on our December 31, 2010 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and processing agreements that allow our production to flow through third-party processing facilities.
- Capital leases include pipeline commitments primarily related to production at Long Lake.
- Work commitments include non-discretionary capital spending for drilling, seismic, facilities construction and other development commitments in our international operations, and include commitments for the Usan development project in Nigeria over the next five years. Since the timing of certain payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have included $914 million in work commitments for drilling rigs we have contracted in the UK, Norway and the Gulf of Mexico over the next five years.

- We have $2,552 million of undiscounted asset retirement obligations after inflation. As of December 31, 2010, the discounted value ($1,064 million) of these estimated obligations was provided for in our Consolidated Financial Statements (including $55 million of estimated current obligations). Since timing of any payments is difficult to determine with certainty, the table was prepared using our best estimates.
- We have a net pension liability of $76 million for our defined benefit pension plan. This includes a pension asset of $21 million from excess contributions to the defined benefit plan, offset by a liability of $97 million for supplemental pension benefits. Supplemental pension benefits are funded from our operating cash flows and backed with an irrevocable letter of credit. Our share of the unfunded pension obligation for Syncrude is $64 million.
- We have excluded obligations on our tandem option, stock appreciation rights and restricted share units programs as the amount and timing of cash payments are not determinable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and capital expenditures for 2011.
- We have excluded our future income tax liabilities as the amount and timing of any cash payment for income taxes is based on taxable income for each fiscal year in the various jurisdictions where we operate. We have also excluded future income tax liabilities as they relate to uncertain tax positions, as we cannot provide a reasonable estimate as to if, or when, future payments would be required.

From time to time, we enter into contracts that require us to indemnify parties against certain possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. We believe existing indemnifications would not have a material adverse effect on our liquidity, financial condition or results of operations.

CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect: i) the reported amounts of our assets and liabilities; ii) the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements; and iii) our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of commodity trading inventories, fair values of derivative assets and liabilities, capital adequacy and the estimation of reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

Oil and Gas Accounting—Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated remaining reserves. The process of estimating reserves requires complex judgements and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions. Refer to the Basis of Reserves Estimates on pages 31 to 34 for a description of our process for estimating reserves.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and, if not, we expense the costs immediately. In 2010, $64 million of our total $413 million spent on exploration drilling was expensed. If all of our exploration drilling was successful in 2010, our net income would have increased by $39 million, net of income tax;

- calculating our unit-of-production depletion rates. Both proved and proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired, and proved developed reserves are used where a property is drilled and developed. In 2010, oil and gas depletion of $1,528 million (before impairments) was recorded in depletion, depreciation, amortization and impairment expense. If our proved reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $153 million, assuming no other changes to our reserves profiles or impairments as described below; and
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved and probable reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

Impairments

PROPERTY, PLANT AND EQUIPMENT

We evaluate our long-lived assets for impairment if an adverse event or change occurs. Among other things, these might include falling oil and gas prices, a significant negative revision to our reserve estimates, changes in operating and capital costs or significant or adverse political or regulatory changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected assets to determine if they are impaired. If the undiscounted future cash flow for an asset is less than the carrying amount of that asset, we estimate its fair value using a discounted cash flow model.

Cash flow estimates for our impairment assessments require assumptions about the following primary elements: future prices and costs, reserves and discount rates. Our estimates of future prices are based on our assumptions of long-term prices and operating and development costs and require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US$32.40/bbl to US$147.27/bbl and US$2.41/mmbtu to US$13.69/mmbtu, respectively. Our forecasts for oil and gas revenues for impairment assessment are based on prices derived from a consensus of future price forecasts amongst industry analysts, our own assessments and existing market future prices. Our estimates of discount rates include consideration of the marketplace and risk of the asset. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessments of impairment to be a critical accounting estimate. A change in these estimates would impact all our businesses with the exception of energy marketing.

The relationship between our reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

GOODWILL

We test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount and at least annually. Our goodwill impairment test compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds the fair value, the goodwill is considered impaired. To measure the amount of impairment, we allocate the estimated fair value to the underlying assets and liabilities, resulting in an implied fair value of goodwill. If the carrying amount of the goodwill exceeds the implied fair value, an impairment loss equal to the excess is included in net income.

The process of assessing goodwill for impairment requires us to estimate the fair values of our assets using one or more valuation techniques, including present-value calculations of estimated future cash flows. This process involves making various assumptions and judgments about future commodity prices, future activity levels, operating costs and discount rates. Changes in any of these assumptions or judgments could result in an impairment of all or a portion of goodwill.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating the related damage caused. In estimating our future asset retirement obligations, we must make estimates and judgments on activities that will occur many years from now. Additionally, contracts and regulations are often vague and unclear as to what constitutes removal and remediation. Furthermore, the ultimate financial impact is not always clearly known and cannot be reasonably estimated as asset removal and remediation techniques and costs are constantly changing, as are legal, regulatory, environmental, political, safety and other such considerations.

We record asset retirement obligations in our Consolidated Financial Statements by discounting the future value of the estimated retirement obligations associated with our oil and gas wells and facilities and other assets. In arriving at amounts recorded, numerous assumptions and judgments are made on ultimate settlement amounts, inflation factors, discount rates, timing of settlement and expected changes in legal, regulatory, environmental, political and safety environments. The asset retirement obligations we record increase the carrying cost of our property, plant and equipment and accrete with the passage of time.

A change in any one of our assumptions could impact our asset retirement obligations, the carrying value of our property, plant and equipment and our DD&A expense.

Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and income tax purposes. We carry on business in several countries and, as a result, we are subject to income taxes in numerous jurisdictions. The determination of current income tax is inherently complex, interpretations will vary, and we are required to make certain judgments. Our income tax filings are subject to audits and reassessments and we believe we have adequately provided for all income tax obligations. However, changes in facts, circumstances and interpretations as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

Derivatives and Fair Value Measurements

We enter into contracts to purchase and sell energy commodities (primarily crude oil) and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively, derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We also carry commodity trading inventory held for trading purposes at fair value.

The fair value of derivative contracts and commodity inventories is estimated. Wherever possible, this estimate is based on quoted market prices and, if not available, on estimates from third-party brokers. We classify the fair value of our derivatives according to a three-level hierarchy based on the amount of observable inputs used to value the instruments. Inputs may be: i) readily observable; ii) market corroborated; or iii) generally unobservable. We utilize valuation techniques that maximize the use of observable inputs wherever possible and minimize the use of unobservable inputs. Another significant assumption that we use in determining the fair value of derivatives is market data or assumptions that market participants would use when pricing the asset or liability, including assumptions about risk.

Our assessment of the significance of a particular input to the fair value measurement may affect the valuation of fair value within the hierarchy. Also for derivative contracts, the time between inception and settlement of the contract may affect fair value. The actual settlement of derivatives could differ materially from the fair value recorded and could impact future operating results. We performed a sensitivity analysis of inputs used to calculate the fair value of the instruments that are based on unobservable inputs. Using reasonably possible alternative assumptions, the fair value of these instruments would change by $5 million (before tax) at December 31, 2010.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

INTERNATIONAL FINANCIAL REPORTING STANDARDS ADOPTION PLAN

We are required to adopt International Financial Reporting Standards (IFRS) for our interim and annual financial reporting purposes beginning January 1, 2011. A project team, consisting of dedicated and experienced personnel who have IFRS knowledge, has been set up to manage this transition and to ensure successful implementation within the required time frame. The adoption of IFRS will not have an impact on our operations or strategic decisions.

A steering committee comprised of senior management has been established for project oversight. The steering committee has the responsibility to ensure the project is adequately planned in sufficient detail, appropriate resources are made available, necessary milestones are established and project progress is properly monitored. These senior leaders are also responsible for internal controls over financial reporting and our disclosure controls and procedures. The Audit and Conduct Review Committee of the Board of Directors regularly receives progress reporting of the status of the IFRS transition project and the training of IFRS principles.

Our project consists of five phases: diagnostic, design and plan, develop solution, implementation and closeout. We are currently in the late stages of the implementation phase, where we have made the changes to business processes, financial reporting and information technology systems, which allowed us to capture IFRS financial information throughout 2010. During the last stage of implementation, we are making the final changes to processes and systems to allow us to complete our transition to IFRS-compliant financial information capture and reporting, and conclude our detailed analysis of potential adjustments to our IFRS opening balance sheet as of January 1, 2010.

Project activities and key milestones are documented in the following chart:

Key Activity	Key Milestone	Status
Financial Information		
• Identify differences between Canadian GAAP and IFRS • Revise accounting policies under IFRS • Identify potential adjustments to initial IFRS financial statements • Develop IFRS-compliant financial statements, including transitional disclosures	• Comprehensive analysis of IFRS differences identified in the diagnostics phase • Senior management approval of IFRS accounting policies • Quantification of all identified potential adjustments to initial IFRS financial statements • Develop draft IFRS financial statements and disclosures, including opening balance sheet adjustments	• Comprehensive analysis completed mid 2009 • Received senior management approval of IFRS accounting policies • Areas of potential adjustment to opening balance sheet have been identified and calculations are in progress • Adjustments to initial IFRS financial statements are being finalized • Draft IFRS financial statements and note disclosures are complete
Training and Communication		
• Develop and deliver targeted IFRS training to employees and management • Ensure internal and external stakeholders receive ongoing appropriate communications • Develop and deliver targeted IFRS training to senior management and board of directors	• Delivery of training targeted to affected employees • Ongoing communication with major internal and external stakeholders • Ongoing review of project by Audit Committee	• Targeted training completed in 2009 • Follow-up training in 2010 was completed • Regular communication with project steering committee, senior management and Audit Committee throughout the year • Quarterly disclosures of project status in MD&A
Information Technology		
• Ensure systems are able to adequately support conversion to IFRS and ongoing financial reporting	• Be IFRS data capture ready January 1, 2010 • Ensure dual GAAP reporting capability throughout 2010 • Ensure systems support IFRS compliant financial reporting January 1, 2011	• System testing for dual GAAP reporting data capture complete • Dual GAAP data capture and reporting occurred throughout 2010 • Testing of final systems and data conversion for 2011 completed, with live execution expected in Q1 2011
Business Process		
• Ensure business processes and control environment properly support conversion to IFRS and ongoing financial reporting	• Complete review of business processes and controls over financial reporting	• Business processes and controls over financial reporting have been updated in 2010 • Internal documentation has been updated to reflect accounting policies in accordance with IFRS

Expected Accounting Policy Impacts

We determined that the majority of our existing Canadian GAAP oil and gas accounting policies are appropriate under IFRS as we currently use successful efforts accounting for our oil and gas activities. However, detailed analysis has identified differences, the most significant of which will impact certain aspects of our accounting for property, plant and equipment, asset retirement obligations, impairments of assets, accounting for income taxes, and share-based payments as described below. Generally, most of these transitional adjustments will be made to opening retained earnings on January 1, 2010.

The draft accounting policies we have prepared in accordance with IFRS are based upon our interpretations of the IFRS that are currently issued. Our draft IFRS accounting policies and transitional exemptions may change based on revised interpretations or changes in IFRS up to December 31, 2011. The following information summarizes the adjustments required to restate our opening Consolidated Balance Sheet at January 1, 2010 on adoption of IFRS:

(Cdn$ millions)	Canadian GAAP	IFRS Adjustments	IFRS
Current Assets	5,551	–	5,551
Long–Term Assets	17,349	(800) to (900)	16,449 to 16,549
Total Assets	**22,900**	**(800) to (900)**	**22,000 to 22,100**
Current Liabilities	3,153	90 to 110	3,243 to 3,263
Long–Term Liabilities	12,101	(90) to (110)	11,991 to 12,011
Equity	7,646	(800) to (900)	6,746 to 6,846
Total Liabilities and Equity	**22,900**	**(800) to (900)**	**22,000 to 22,100**

PROPERTY, PLANT AND EQUIPMENT

Significant components of property, plant and equipment (PP&E) with different useful lives must be accounted for and depreciated separately. Instances of major maintenance, turnarounds or inspections must also be capitalized and depreciated until the next scheduled major maintenance activity. Our current policy is to expense these items unless they result in improvements that increase capacity or extend the useful life. We expect that retrospective application will decrease our net PP&E on January 1, 2010 by approximately $40 million.

ASSET RETIREMENT OBLIGATIONS

There are differences in the calculation methodology for determining asset retirement obligations, the most significant of which is the use of a risk-free rate to discount our obligations under IFRS. Under Canadian GAAP, our obligations were discounted using a credit-adjusted risk-free discount rate. Additionally, liabilities must be re-measured at each balance sheet date using current discount rates under IFRS, whereas under Canadian GAAP, discount rates do not change once the liability is recorded. We expect the transitional impact of these adjustments will increase our accrued asset retirement obligations on January 1, 2010 by approximately $380 million and increase our PP&E by approximately $150 million.

IMPAIRMENT OF ASSETS

Under Canadian GAAP, if indicators of potential impairment existed and carrying value exceeded future undiscounted cash flows, assets were impaired to the lower of fair value or cost. Under IFRS, there is no requirement to compare the carrying value with future undiscounted cash flows; instead, if there are indicators of potential impairment, the asset's carrying value is immediately compared to estimated fair value and carried at the lower of fair value or cost. As a result, we believe that asset impairments may occur more frequently under IFRS. Additionally, IFRS requires that previously recorded impairments for assets other than goodwill be reversed if the recoverable amount subsequently increases.

ACCOUNTING FOR INCOME TAXES

IFRS requires us to recognize tax benefits related to a one-time tax deduction in the UK in the period in which they occur. Canadian GAAP requires us to defer recognition of the benefit until the assets are recognized in income by way of a sale to a third party or depletion through use. Additionally, in transitioning to IFRS, our deferred tax liability will be impacted by the tax effects resulting from the IFRS changes discussed in this section. We expect that our future income tax liability will decrease by approximately $60 million and related deferred credits will decrease approximately $500 million on transition to IFRS.

SHARE-BASED PAYMENTS

We use the intrinsic method to account for our cash-settled stock-based compensation under Canadian GAAP. We will use a fair value model such as Black-Scholes to value our stock-based compensation under IFRS. We expect that the IFRS requirement to value stock-based compensation at fair value each reporting period may result in less volatility in our reported earnings each period. We expect the transitional impact of this adjustment will increase our accrued liabilities on January 1, 2010 by approximately $100 million.

ONE TIME ADJUSTMENTS ON TRANSITION TO IFRS

IFRS allows certain adjustments to financial information on transition where retrospective restatement would either be onerous or would not provide more useful information. We expect to make one-time transitional adjustments on January 1, 2010 as follows:

- Borrowing costs previously capitalized under Canadian GAAP will be de-recognized and borrowing costs will be prospectively capitalized under IFRS from January 1, 2010. PP&E is expected to decrease approximately $840 million as a result;
- PP&E will decrease to reflect the use of fair value as deemed cost on transition for certain of our assets where the carrying values of the assets are in excess of their fair values on January 1, 2010. PP&E is expected to decrease approximately $100 million;
- Defined benefit pension obligations will be increased to reflect previously unrecognized net actuarial gains and losses. The increase to liabilities is expected to be approximately $100 million; and
- Accumulated foreign exchange gains and losses within accumulated other comprehensive income will be reset to zero rather than retrospectively restating the balance. The decrease to accumulated other comprehensive income is expected to be approximately $190 million.

We expect that the net impact of adopting IFRS will reduce our shareholders' equity by approximately $800 to $900 million and the impact on our cash flows from operating activities will be immaterial.

In addition to the differences identified above, we continue to monitor the development of new standards and any changes will be incorporated as required.

As a foreign private issuer in the US, we are permitted to file financial statements prepared under IFRS without reconciliation to US GAAP. Effective January 1, 2011, we will adopt IFRS as our basis of accounting. As a result, we will no longer prepare a reconciliation of our results to US GAAP. It is possible that certain of our accounting policies under IFRS could be different from US GAAP, although we expect that most accounting policies will remain consistent or converge with US GAAP as the International Accounting Standards Board (IASB) and Financial Accounting Standards Board (FASB) undertake joint projects.

US Pronouncements

On January 6, 2010, the Financial Accounting Standards Board issued guidance for *Oil and Gas Reserve Estimation and Disclosure*, which was effective for years ended December 31, 2009. The guidance: i) expands the definition of oil and gas producing activities to include unconventional sources such as oil sands; ii) changes the price used in reserve estimation from the year-end price to the simple average of the first-day-of-the-month price for the previous 12 months; and iii) require disclosures for geographic areas that represent 15% or more of proved reserves.

We follow the successful efforts method of accounting for our oil and gas activities, which use the estimated proved reserves we believe are recoverable from our oil and gas properties. Specifically, reserves estimates are used to calculate our unit-of-production depletion rates and to assess, when necessary, our oil and gas assets for impairment. Adoption of the amendments changed our estimate of reserves used to calculate depletion in 2010. As a result of the amendments, for the year ended December 31, 2010, depletion expense increased by $47 million, net income decreased by $32 million, and earnings per common share decreased by $0.07/share.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to normal market risks inherent in the oil and gas and energy marketing businesses, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

COMMODITY PRICE RISK

Commodity price risk related to crude oil prices is our most significant market risk exposure. Crude oil and natural gas prices are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for exploration and development.

Our realized crude oil prices are based on various reference prices, primarily WTI and Brent and other prices that generally track the movement of WTI and Brent. Actual prices realized differ from the reference prices to reflect quality differentials and transportation. WTI, Brent and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

We are also exposed to natural gas price movements. Natural gas prices are generally influenced by supply and demand fundamentals and, to a lesser extent, local market conditions and oil prices.

In 2010, WTI averaged US$79.52/bbl, reaching a high of US$92.06/bbl and a low of US$64.24/bbl. Dated Brent, on which approximately 80% of our crude oil production is priced, averaged US$79.47/bbl, reaching a high of US$94.00/bbl and a low of US$67.58/bbl. Currently, Brent is trading at US$101.64/bbl. NYMEX natural gas prices averaged US$4.39/mmbtu in 2010, reaching a high of US$6.11/mmbtu and a low of US$3.21/mmbtu. Our sensitivities to commodity prices and the expected impact on our 2010 cash flow from operating activities and were included on page 97 of this MD&A.

These sensitivities are based on our estimated 2011 oil and gas production and assume a US/Canadian dollar exchange rate of $1.00. Our estimated oil and gas production range for 2011 is between 230,000 and 270,000 boe/d before royalties, of which approximately 18% is gas.

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In 2010, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2011. These put options have established a monthly average WTI floor price of between US$50/bbl and US$63/bbl on about 100,000 bbls/d of production.

Our energy marketing group's primary focus is to market proprietary crude oil production from North America, the North Sea and Yemen. We also buy and sell third-party production. In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two-day holding period in our measure, although actual results can differ from this estimate in non-normal market conditions or if positions are held longer than two days based on market views or a lack of market liquidity to exit them, which is typical for long-term assets. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor and report our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

(Cdn$ millions)	2010	2009	2008
Value-at-Risk			
Year-End	11	11	25
High	15	24	40
Low	4	9	19
Average	10	15	30

If a market shock occurred as in 2008, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of non-normal changes in prices on our positions.

FOREIGN CURRENCY RISK

A substantial portion of our activities are transacted in or referenced to US dollars, including:

- sales of crude oil and natural gas;
- capital spending and expenses for our oil and gas operations; and
- short-term and long-term borrowings.

The US/Canadian dollar exchange rate averaged $0.97 in 2010, ranging from a low of $0.93 to a high of $1.01.

Our sensitivities to the US dollar and the expected impact of a one-cent change on our 2011 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

(Cdn$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-Term Debt
$0.01 Change in US to Cdn	26	15	16	53

Our sensitivities to changes in the US/Canadian dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar-denominated long-term debt for 2011. These estimates are based on a WTI price of US$75/bbl, a NYMEX natural gas price of US$4.00/mmbtu and a US/Canadian dollar exchange rate of $1.00.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations.

We do not have any material exposure to highly inflationary foreign currencies.

INTEREST RATE RISK

We are exposed to changes in interest payments on any floating-rate debt as interest rates fluctuate. Our only floating-rate debt is our term credit facilities which are expected to be used minimally and therefore, we expect our sensitivity to changes in interest rates on our 2011 cash flow and net income to be immaterial.

CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Over 80% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a rigorous credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our executive risk management committee and the Finance Committee of the Board;
- set counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis;
- review counterparty credit limits regularly;
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty; and
- utilize terms of agreements to request collateralization as determined appropriate when the credit risk deteriorates.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance.

At December 31, 2010, three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade ratings. Two other counterparties made up more than 5% of our credit exposure. The following table illustrates the composition of credit exposure by credit rating:

Credit Rating	2010	2009
A or Higher	71%	67%
BBB	20%	26%
Non-investment Grade	9%	7%
Total	**100%**	**100%**

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We have provided an allowance of $44 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as our own credit risk, into our estimates of fair value.

Non-GAAP Measures

CASH FLOW FROM OPERATIONS

Cash flow from operations is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash working capital and other, and excludes items of a non-recurring nature. We evaluate our performance and that of our business segments based on earnings and cash flow from operations. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt. Cash flow from operations is unlikely to be comparable with the calculation of similar measures for other companies.

(Cdn$ millions)	**2010**	**2009**	**2008**
Cash Flow from Operating Activities	2,349	1,886	4,354
Changes in Non-Cash Working Capital	(338)	25	(119)
Other	159	318	18
Impact of Annual Crude Oil Put Options	(40)	(14)	(24)
Cash Flow from Operations	**2,130**	**2,215**	**4,229**

NET DEBT

Net debt is a non-GAAP measure defined as long-term debt and short-term borrowings less cash and cash equivalents. We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly tied to our operating cash flows and capital investment. Net debt is unlikely to be comparable with the calculation of similar measures for other companies.

(Cdn$ millions)	**2010**	**2009**	**2008**
Bank Debt	–	1,803	1,448
Public Senior Notes	4,636	4,982	4,582
Total Senior Debt	**4,636**	**6,785**	**6,030**
Subordinated Debt	443	466	548
Total Debt	**5,079**	**7,251**	**6,578**
Less: Cash and Cash Equivalents	(1,005)	(1,700)	(2,003)
Total Net Debt	**4,074**	**5,551**	**4,575**

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees in Note 15 to the Consolidated Financial Statements, which is incorporated herein by reference.

At December 31, 2010, we had outstanding letters of credit supported by $322 million (US$324 million) of unsecured term credit facilities and $112 million (US$112 million) of uncommitted unsecured credit facilities.

Transactions with Related Parties

As a Canadian foreign private issuer, Nexen provides the disclosure required under Item 1.9 of Form 51-102F1 dealing with "transactions with related parties". Nexen did not have any related party transactions in 2010. Certain other transactions involving Nexen and certain directors were entered into in 2010 and are described under "Director Independence" in our AIF. These are not related party transactions.

Additional Information

Additional information, including our AIF and our Consolidated Financial Statements, is available from our public filings with both the SEC and the Canadian Securities Administrators at www.sec.gov and www.sedar.com, respectively or from our website www.nexeninc.com.

On January 31, 2011, there were 526,082,903 common shares issued and outstanding.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute "forward-looking statements" (within the meaning of the *United States Private Securities Litigation Reform Act of 1995*, as amended) or "forward-looking information" (within the meaning of applicable Canadian securities legislation). Such statements or information (together "forward-looking statements") are generally identifiable by the forward-looking terminology used such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil or natural gas prices; future production levels; future royalties and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for our capital program; future debt levels; availability of committed credit facilities; possible commerciality of our projects; development plans or capacity expansions; the expectation that we have the ability to substantially grow production at our oil sands facilities through controlled expansions; the expectation of achieving the production design rates from our oil sands facilities; the expectation that our oil sands production facilities continue to develop better and more sustainable practices; the expectation of cheaper and more technologically advanced operations; the expected design size of our facilities; the expected timing and associated production impact of facilities turnarounds and maintenance; the expectation that we can continue to operate our offshore exploration, development and production facilities safely and profitably; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected finding and development costs; expected operating costs; future cost recovery oil revenues from our Yemen operations; the expectation of negotiating of an extension to certain of our production sharing agreements; the expectation of our ability to comply with the new safety and environmental rules enacted in the US at a minimal incremental cost, and of receiving necessary drilling permits for our US offshore operations; estimates on a per share basis; future foreign currency exchange rates; future expenditures and future allowances relating to environmental matters and our ability to comply with them; dates by which certain areas will be developed, come on stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

All of the forward-looking statements in this MD&A are qualified by the assumptions that are stated or inherent in such forward-looking statements. Although we believe that these assumptions are reasonable, this list is not exhaustive of the factors that may affect any of the forward-looking statements and the reader should not place an undue reliance on these assumptions and such forward-looking statements. The key assumptions that have been made in connection with the forward-looking statements include the following: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty

and regulatory regimes; the accuracy of the estimates of our reserve volumes; commodity price and cost assumptions; the continued availability of adequate cash flow and debt and/or equity financing to fund our capital and operating requirements as needed; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for oil and gas; our ability to explore, develop, produce, upgrade and transport crude oil and natural gas to markets; ultimate effectiveness of design or design modifications to facilities; the results of exploration and development drilling and related activities; the cumulative impact of oil sands development on the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; the availability of pipeline and global refining capacity; risks inherent to the operations of any large, complex refinery units, especially the integration between production operations and an upgrader facility; availability of third-party bitumen for use in our oil sands production facilities; labour and material shortages; risks related to accidents, blowouts and spills in connection with our offshore exploration, development and production activities, particularly our deep-water activities; direct and indirect risks related to the imposition of moratoriums, suspensions or cancellations of our offshore exploration, development and production operations, particularly our deep-water activities; the impact of severe weather on our offshore exploration, development and production activities, particularly our deep-water activities; the effectiveness and reliability of our technology in harsh and unpredictable environments; risks related to the actions and financial circumstances of our agents and contractors, counterparties and joint venture partners; volatility in energy trading markets; foreign currency exchange rates; economic conditions in the countries and regions in which we carry on business; governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations including without limitation, those related to our offshore exploration, development and production activities; renegotiations of contracts; results of litigation, arbitration or regulatory proceedings; political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict, including conflict between states; and other factors, many of which are beyond our control. These risks, uncertainties and other factors and their possible impact are discussed more fully in the sections titled Risk Factors in this AIF and Quantitative Disclosures About Market Risk in our MD&A. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements. Undue reliance should not be placed on the forward-looking statements contained herein, which are made as of the date hereof and, except as required by law, Nexen undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Included herein is information that may be considered financial outlook and/or future-oriented financial information (FOFI). Its purpose is to indicate the potential results of our intentions and may not be appropriate for other purposes. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

CONSOLIDATED FINANCIAL STATEMENTS

Drilling in the deep-water Gulf of Mexico

Nexen Inc. Consolidated Financial Statements

NEXEN INC. CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF MANAGEMENT

February 16, 2011

To the Shareholders of Nexen Inc.

We are responsible for the preparation and fair presentation of the Consolidated Financial Statements, as well as the financial reporting process that gives rise to such Consolidated Financial Statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our Consolidated Financial Statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for developing and implementing internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company and that our records are reliable for preparing our Consolidated Financial Statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer or Controller.

Our Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement-related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (Audit Committee), with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves, and the Finance Committee regarding the assessment and mitigation of financial risk. The Audit Committee is composed entirely of independent directors and includes five directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent registered Chartered Accountants and also considers their independence, reviews their fees and (subject to applicable securities laws) pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with and without the presence of management.

(signed) "Marvin F. Romanow
President and Chief Executive Officer

(signed) "Kevin J. Reinhart"
Executive Vice President and Chief Financial Officer

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13(a)–15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control—Integrated Framework* issued by the *Committee of Sponsoring Organizations of the Treadway Commission*. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2010. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Deloitte & Touche LLP audited our Consolidated Financial Statements as stated in their report and has provided an attestation report on our internal control over financial reporting.

REPORTS OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the accompanying consolidated financial statements of Nexen Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of income, cash flows, equity and comprehensive income for each of the years in the three year period ended December 31, 2010, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2010 and 2009, and the results of their operations and cash flows for each of the years in the three year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Emphasis of Matter

We draw your attention to Note 1(U) to the consolidated financial statements which describe the adoption of the Financial Accounting Standards Board guidance for Oil and Gas Reserve Estimation and Disclosure, which is effective for years ended on or after December 31, 2009. Our opinion is not qualified in respect of this matter.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 16, 2011

To the Board of Directors and Shareholders of Nexen Inc.

We have audited the internal control over financial reporting of Nexen Inc. and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2010, and our report dated February 16, 2011, expressed an unqualified opinion on those financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants
Calgary, Canada
February 16, 2011

NEXEN INC.
CONSOLIDATED STATEMENT OF INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

(Cdn$ millions, except per-share amounts)	**2010**	**2009**	**2008**
Revenues and Other Income			
Net Sales	5,411	4,203	6,576
Marketing and Other (Note 16)	415	859	863
	5,826	5,062	7,439
Expenses			
Operating	1,354	916	924
Depreciation, Depletion, Amortization and Impairment (Note 4)	1,662	1,615	1,899
Transportation and Other	566	732	907
General and Administrative	439	434	210
Exploration	328	302	401
Interest (Note 9)	310	305	82
Net Loss on Dispositions (Note 18)	41	–	–
	4,700	4,304	4,423
Income from Continuing Operations before Provision for Income Taxes	1,126	758	3,016
Provision for (Recovery of) Income Taxes (Note 17)			
Current	1,127	773	857
Future	(573)	(527)	557
	554	246	1,414
Net Income from Continuing Operations	572	512	1,602
Net Income from Discontinued Operations, Net of Tax (Note 20)	625	24	113
Net Income Attributable to Nexen Inc.	**1,197**	**536**	1,715
Earnings Per Common Share from Continuing Operations *($/share)* (Note 21)			
Basic	1.09	0.98	3.05
Diluted	1.08	0.96	3.01
Earnings Per Common Share *($/share)* (Note 21)			
Basic	2.28	1.03	3.26
Diluted	2.27	1.01	3.22

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2010 AND 2009

(Cdn$ millions, except share amounts)	**2010**	**2009**
ASSETS		
Current Assets		
Cash and Cash Equivalents	1,005	1,700
Restricted Cash	40	198
Accounts Receivable (Note 2)	1,938	2,788
Inventories and Supplies (Note 3)	549	680
Other	142	185
Assets Held for Sale (Note 20)	748	–
Total Current Assets	4,422	5,551
Property, Plant and Equipment (Note 4)	15,249	15,492
Future Income Tax Assets (Note 17)	1,678	1,148
Goodwill	286	339
Deferred Charges and Other Assets (Note 5)	272	370
TOTAL ASSETS	**21,907**	**22,900**
LIABILITIES		
Current Liabilities		
Accounts Payable and Accrued Liabilities (Note 8)	2,545	3,038
Accrued Interest Payable	83	89
Dividends Payable	26	26
Liabilities Held for Sale (Note 20)	540	–
Total Current Liabilities	3,194	3,153
Long-Term Debt (Note 9)	5,079	7,251
Future Income Tax Liabilities (Note 17)	3,138	2,811
Asset Retirement Obligations (Note 11)	1,009	1,018
Deferred Credits and Other Liabilities (Note 12)	696	1,021
EQUITY (Note 14)		
Nexen Inc. Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2010—525,706,403 shares		
2009—522,915,843 shares	1,111	1,049
Contributed Surplus	–	1
Retained Earnings	7,815	6,722
Accumulated Other Comprehensive Loss	(219)	(190)
Total Nexen Inc. Shareholders' Equity	8,707	7,582
Canexus Non-Controlling Interests (Note 20)	84	64
Total Equity	8,791	7,646
Commitments, Contingencies and Guarantees (Notes 15, 17 and 18)		
TOTAL LIABILITIES AND EQUITY	**21,907**	**22,900**

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Marvin F. Romanow" (signed) "Thomas C. O'Neill"
Director Director

NEXEN INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

(Cdn$ millions)	**2010**	**2009**	**2008**
Operating Activities			
Net Income from Continuing Activities	572	512	1,602
Net Income from Discontinued Operations (Note 20)	630	44	109
Charges and Credits to Income not Involving Cash (Note 22)	640	1,371	2,140
Exploration Expense	328	302	402
Changes in Non-Cash Working Capital (Note 22)	338	(25)	119
Other	(159)	(318)	(18)
	2,349	1,886	4,354
Financing Activities			
Proceeds from Long-Term Notes	–	1,081	–
Repayment of Medium-Term Notes and Debentures	–	–	(125)
Proceeds from (Repayment of) Term Credit Facilities, Net	(1,538)	728	803
Repayment of Short-Term Borrowings, Net	–	(1)	(4)
Proceeds from Canexus Long-Term Debt, Net	112	94	31
Dividends on Common Shares	(104)	(104)	(92)
Distributions Paid to Canexus Non-Controlling Interests	(17)	(14)	(17)
Issue of Common Shares and Exercise of Tandem Options for Shares (Note 14)	55	57	64
Repurchase of Common Shares for Cancellation (Note 14)	–	–	(338)
Other	(14)	(20)	–
	(1,506)	1,821	322
Investing Activities			
Capital Expenditures			
Exploration and Development	(2,313)	(2,467)	(2,895)
Proved Property Acquisitions	(79)	(755)	(22)
Energy Marketing, Chemicals, Corporate and Other	(210)	(275)	(149)
Proceeds on Disposition of Assets	1,262	17	6
Changes in Non-Cash Working Capital (Note 22)	(59)	(110)	(124)
Changes in Restricted Cash	37	(140)	106
Other	(60)	(13)	(111)
	(1,422)	(3,743)	(3,189)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(116)	(267)	310
Increase (Decrease) in Cash and Cash Equivalents	(695)	(303)	1,797
Cash and Cash Equivalents, Beginning of Year	1,700	2,003	206
Cash and Cash Equivalents, End of Year	**1,005**	**1,700**	**2,003**

Cash and cash equivalents at December 31, 2010 consists of cash of $345 million (2009—$210 million; 2008—$355 million) and short-term investments of $660 million (2009—$1,490 million; 2008—$1,648 million).

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

(Cdn$ millions)	2010	2009	2008
Common Shares, Beginning of Year	1,049	981	917
Issue of Common Shares	50	45	41
Exercise of Tandem Options for Shares	5	12	23
Accrued Liability Relating to Tandem Options Exercised for Common Shares	7	11	22
Repurchased Under Normal Course Issuer Bid (Note 14)	–	–	(22)
End of Year	**1,111**	**1,049**	**981**
Contributed Surplus, Beginning of Year	1	2	3
Exercise of Tandem Options	(1)	(1)	(1)
End of Year	**–**	**1**	**2**
Retained Earnings, Beginning of Year	6,722	6,290	4,983
Net Income Attributable to Nexen Inc.	1,197	536	1,715
Dividends Declared on Common Shares	(104)	(104)	(92)
Repurchase of Common Shares for Cancellation (Note 14)	–	–	(316)
End of Year	**7,815**	**6,722**	**6,290**
Accumulated Other Comprehensive Loss, Beginning of Year	(190)	(134)	(293)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(29)	(56)	159
End of Year[1]	**(219)**	**(190)**	**(134)**
Canexus Non-Controlling Interests, Beginning of Year	64	52	67
Net Income (Loss) Attributable to Non-Controlling Interests	5	27	(5)
Distributions Declared to Non-Controlling Interests	(20)	(18)	(20)
Issue of Partnership Units to Non-Controlling Interests	27	4	3
Estimated Fair Value of Conversion Feature of Convertible Debenture Issue Attributable to Non-Controlling Interests	8	4	–
Other Comprehensive Income (Loss) Attributable to Canexus Non-Controlling Interests	–	(5)	7
End of Year	**84**	**64**	**52**

1 Comprised of unrealized foreign currency translation adjustment.

See accompanying notes to Consolidated Financial Statements.

NEXEN INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2010

(Cdn$ millions)	**2010**	**2009**	**2008**
Net Income Attributable to Nexen Inc.	1,197	536	1,715
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment:			
Net Gains (Losses) on Investment in Self-Sustaining Foreign Operations	(257)	(810)	1,228
Net Gains (Losses) on Foreign-Denominated Debt Hedges of Self-Sustaining Foreign Operations[1]	228	757	(1,062)
Realized Translation Adjustments Recognized in Net Income	–	(3)	(7)
Other Comprehensive Income (Loss) Attributable to Nexen Inc.	(29)	(56)	159
Comprehensive Income Attributable to Nexen Inc.	**1,168**	**480**	**1,874**

1 Net of income tax expense for the year ended December 31, 2010 of $33 million (2009—$109 million expense; 2008—$145 million recovery).

See accompanying notes to Consolidated Financial Statements.

Cdn$ millions, except as noted

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 24.

(A) CONSOLIDATION

The Consolidated Financial Statements include the accounts of Nexen and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus Limited Partnership and its subsidiaries (Canexus), are wholly owned. All intercompany accounts and transactions are eliminated upon consolidation.

At December 31, 2010, we had a 62.7% interest in Canexus represented by 66.2 million Exchangeable LP Units. We had the right to nominate a majority of the members of the Board of Directors, who have the power to determine the strategic operating, investing and financing policies of Canexus. All assets, liabilities and results of operations of Canexus are consolidated and have been included in our Consolidated Financial Statements. Non-Nexen ownership interests in Canexus are shown as non-controlling interests. As disclosed in Notes 19 and 20, we sold our interest in Canexus in early 2011 and the assets, liabilities and operating results were reclassified as held for sale and discontinued operations as at December 31, 2010.

We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities. The significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(B) USE OF ESTIMATES

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates on an ongoing basis, including those related to accruals, litigation, environmental and asset retirement obligations, recoverability of assets, income taxes, fair values of commodity trading inventories, fair values of derivative assets and liabilities, capital adequacy and the determination of proved reserves. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(C) CASH AND CASH EQUIVALENTS

Cash and cash equivalents includes short-term, highly liquid investments that mature within three months of their purchase. These investments are recorded at cost, which approximates fair value.

(D) RESTRICTED CASH

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts used in our energy marketing business.

(E) ACCOUNTS RECEIVABLE

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(O)). Our allowance for doubtful accounts provides for specific doubtful receivables, as well as general counterparty credit risk evaluated using observable market information and internal assessments.

(F) INVENTORIES AND SUPPLIES

Inventories and supplies, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined using the first-in, first-out method. Inventory costs include expenditures and other costs, including depletion and depreciation, directly or indirectly incurred in bringing the inventory to its existing condition.

Commodity inventories in our energy marketing operations that are held for trading purposes are carried at fair value, less any costs to sell. Any changes in fair value are included as gains or losses in marketing and other income during the period of change.

(G) PROPERTY, PLANT AND EQUIPMENT (PP&E)

PP&E is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E. Major spare parts and standby equipment whose useful life is expected to last longer than one year are included with PP&E.

We follow successful efforts accounting for our oil and gas operations. Costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the costs are reclassified to proved property costs. Exploration drilling costs are capitalized as suspended exploration well costs pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized if a determination is made that a sufficient quantity of reserves has been found and sufficient progress is being made to assess the reserves and the economic and operating viability of a potential development. All other exploration costs, including geological and geophysical costs and annual lease rentals, are expensed as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established and we intend to proceed with development. We defer these costs in PP&E until the asset is substantially complete and ready for productive use. Otherwise, development costs are expensed as incurred.

(H) DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs are depleted over remaining proved reserves. DD&A is considered a cost of inventory when the oil and gas are produced. When the inventory is sold, the depletion is charged to DD&A expense.

We depreciate other plant and equipment costs using the straight-line method based on the estimated useful lives of the assets, which range from 3 to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur which might indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. If the carrying value exceeds the sum of estimated undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated future discounted net cash flows, and we expense the excess carrying value to DD&A. Our cash flow estimates require assumptions about future commodity prices, ultimate recoverability of oil and gas reserves, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(I) CAPITALIZED INTEREST

We capitalize interest on major development projects until construction is complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest incurred.

(J) CARRIED INTEREST

We conduct certain international operations jointly with foreign governments in accordance with production-sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs is recorded in operating expense when incurred, and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(K) GOODWILL

Our goodwill is primarily attributable to our United Kingdom operating segment. It has been recorded at cost and is not amortized. We test goodwill for impairment at least annually or whenever events or circumstances indicate that goodwill may be impaired. We base our test on the estimated fair value of the reporting unit. If goodwill is impaired, we reduce the carrying value to estimated fair value and an impairment loss is included in net income.

(L) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

All financial assets and liabilities are recognized on the balance sheet initially at fair value when we become a party to the contractual provisions of the instrument. Subsequent measurement of the financial instruments is based on their classification. We have classified each financial instrument into one of the following categories: financial assets and liabilities held for trading, loans or receivables, financial assets held to maturity, financial assets available for sale and other financial liabilities. The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in limited circumstances, the classification of financial instruments is not subsequently changed.

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Realized and unrealized gains and losses from financial assets and liabilities carried at fair value are recognized in net income in the periods such gains and losses arise. Transaction costs related to these financial assets and liabilities are included in net income when incurred.

Financial instruments we carry at cost or amortized cost include our accounts receivable, accounts payable and accrued liabilities, accrued interest payable, dividends payable, short-term borrowings and long-term debt. Transaction costs are included in net income when incurred for these types of financial instruments except for short-term borrowings and long-term debt. These transaction costs are included with the initial fair value, and the instrument is carried at amortized cost using the effective interest rate method. Gains and losses on financial assets and liabilities carried at cost or amortized cost are recognized in net income when these assets or liabilities settle.

Derivatives related to non-trading activities

We may use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Notes 6 and 7). We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change unless the requirements for hedge accounting are met.

Derivatives related to trading activities

Our energy marketing operations use derivative instruments for marketing and trading crude oil, natural gas, natural gas liquids and power, including commodity contracts settled with physical delivery, exchange-traded futures and options, and non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other income during the period of change. The fair value of these instruments is included with accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months, we include them with deferred charges and other assets or deferred credits and other liabilities.

Hedge accounting

Hedge accounting may be used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. Derivative instruments that have been designated and qualify for hedge accounting are classified as either cash flow or fair value hedges.

For cash flow hedges, changes in the fair value of a financial instrument designated as a cash flow hedge are recognized in net income in the same period as the hedged item. Any fair value change in the financial instrument before that period is recognized on the balance sheet. The effective portion of this fair value change is recognized in other comprehensive income, with any ineffectiveness recognized in marketing and other income during the period of change.

For fair value hedges, both the financial instrument designated as a fair value hedge and the underlying commitment are recognized on the balance sheet at fair value. Changes in the fair value of both are reflected in net income.

Nexen had no cash flow or fair value hedges in place at December 31, 2010 or 2009.

For hedges of net investments, gains and losses resulting from foreign exchange translation of our net investments in self-sustaining foreign operations and the effective portion of the hedging items are recorded in other comprehensive income. Amounts included in accumulated other comprehensive income are reclassified to income when realized.

(M) ASSET RETIREMENT OBLIGATIONS

We provide for future asset retirement obligations on our resource properties, facilities, production platforms and pipelines based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The obligation is accreted through DD&A expense until it is expected to settle, and the cost is amortized through DD&A expense over the life of the respective asset. The fair value of the obligation is estimated by discounting expected future cash outflows to settle the asset retirement obligation using a weighted-average, credit-adjusted risk-free interest rate. Nexen recognizes period-to-period changes due to the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash outflows. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile, and our interest in the Long Lake upgrader. The estimated future recoverable reserves at Syncrude and Long Lake are significant and, given the long life of these assets, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant and the Long Lake upgrader can both continue to run indefinitely with ongoing maintenance activities. The retirement obligations for these assets will be recorded in the first year in which the obligation to remediate becomes determinable.

(N) PENSION AND OTHER POST-RETIREMENT BENEFITS

Our employee post-retirement benefit programs consist of contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs.

For our defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1% to a maximum increase of 5%. Measurement date for our defined benefit plans is December 31.

Our defined contribution pension plan benefits are based on plan contributions. Company contributions to the defined contribution plan are expensed as incurred.

Other post-retirement benefits include group life and supplemental health insurance for eligible employees and their dependants. Costs are accrued as compensation in the period employees work; however, these future obligations are not funded.

(O) REVENUE RECOGNITION

Oil and gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers primarily take title when the crude oil or natural gas reaches the end of the pipeline. For our other international operations, our customers generally take title when the crude oil is loaded onto tankers. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty obligations to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty obligations. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations.

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery takes place when we have a sales contract specifying delivery volumes and sales prices. We assess customer credit-worthiness before entering into sales contracts to minimize collection risk.

Energy marketing

Substantially all of the physical purchase and sales contracts entered into by our energy marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively, derivative instruments) held by our energy marketing operation are stated at fair value on the balance sheet. We record any change in fair value as a gain or loss in marketing and other income unless requirements for hedge accounting are met.

Any margin earned by our energy marketing operation on the sale of our proprietary oil and gas production is included in marketing and other income. Sales of our proprietary production are recorded at average monthly market-based prices and reported in our oil and gas segments. Intercompany profits and losses between segments are eliminated.

We assess customer credit-worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have a legally enforceable right and intention to offset.

(P) FOREIGN CURRENCY TRANSLATION

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars at the balance sheet date exchange rate for assets and liabilities and at the monthly average exchange rate for revenues and expenses. Gains and losses resulting from this translation are included in other comprehensive income.

We have designated our US-dollar debt (excluding debt related to Canexus) as a hedge against our net investment in US-dollar self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in other comprehensive income. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other income in the Consolidated Statement of Income.

Monetary balance sheet amounts denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation are included in marketing and other income in the Consolidated Statement of Income.

(Q) TRANSPORTATION

We pay to transport the crude oil, natural gas and chemical products that we have sold and often bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as transportation and other expense. Amounts billed to our customers are presented within marketing and other income. Our energy marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments were recorded as deferred liabilities and were recognized in net income as the transportation is used. These obligations were sold in 2010.

(R) LEASES

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases, and the related assets are included with PP&E and amortized on a straight-line basis over the period of expected use, consistent with other PP&E. Rental payments under operating leases are expensed as incurred.

(S) STOCK-BASED COMPENSATION

Our stock-based compensation consists of tandem option (TOPs), stock appreciation right (STARs), and restricted share unit (RSUs) plans.

Tandem options to purchase common shares are granted to officers and employees at the discretion of the Board of Directors. Each tandem option gives the holder a right to either purchase one Nexen common share at the exercise price or to receive a cash payment equal to the excess of the market value of the common share over the exercise price. Options granted vest over three years and are exercisable on a cumulative basis over five years. At the time of the grant, the exercise price equals the market value of the common share. Beginning in 2010, certain awards contain a performance vesting condition.

We record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense in the Consolidated Statement of Income. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the accrued liability is transferred to share capital.

For employees eligible to retire during the vesting period, the compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. In instances where an employee is eligible to retire on the grant date of the stock-based award, compensation expense is recognized in full at that date.

Under our STARs plan, employees are entitled to cash payments equal to the excess of market price of the common share over the exercise price of the right. The vesting period and other terms of the plan are similar to the tandem option plan and include a performance vesting feature for certain awards. At the time of grant, the exercise price equals market value of the common share. We account for stock appreciation rights to employees on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

Under our RSU plan, employees are entitled to receive a cash payment equal to the market value of one common share on the vesting date for each RSU granted. All RSUs vest evenly over three years and are exercised and paid as they vest. The obligation for RSUs are revalued each period based on the market value of our common shares and the number of graded vested RSUs outstanding.

(T) INCOME TAXES

We follow the liability method of accounting for income taxes. This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(U) CHANGES IN ACCOUNTING PRINCIPLES

Oil and gas reserve estimates

On January 6, 2010, the Financial Accounting Standards Board issued guidance for *Oil and Gas Reserve Estimation and Disclosure*, which is effective for years ended on or after December 31, 2009. The guidance: i) expands the definition of oil and gas producing activities to include unconventional sources such as oil sands; ii) changes the price used in reserve estimation from the year-end price to the simple average of the first-day-of-the-month price for the previous 12 months; and iii) requires disclosures for geographic areas that represent 15% or more of proved reserves. The information required by this standard has been included in the Supplementary Data (Unaudited).

We follow the successful efforts method of accounting for our oil and gas activities, which uses the estimated proved reserves we believe are recoverable from our oil and gas properties. Specifically, reserves estimates are used to calculate our unit-of-production depletion rates and to assess, when necessary, our oil and gas assets for impairment. Adoption of the amendments changed our estimate of reserves used to calculate depletion in 2010. As a result of the amendments, depletion expense increased by $47 million, net income decreased by $32 million, and earnings per common share decreased by $0.07/share, for the year ended December 31, 2010.

New accounting pronouncements

Nexen will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

2. ACCOUNTS RECEIVABLE

	2010	2009
Trade		
Energy Marketing	929	1,410
Energy Marketing Derivative Contracts (Note 6)	149	466
Oil and Gas	822	823
Chemicals and Other	2	44
	1,902	2,743
Non-Trade	80	99
	1,982	2,842
Allowance for Doubtful Receivables	(44)	(54)
Total[1]	**1,938**	**2,788**

1 *At December 31, 2010, accounts receivable related to our chemicals operations have been included with assets held for sale (see Notes 19 and 20).*

3. INVENTORIES AND SUPPLIES

	2010	2009
Finished Products		
Energy Marketing	452	548
Oil and Gas	34	25
Chemicals and Other	–	12
	486	585
Work in Process	5	7
Field Supplies	58	88
Total[1]	**549**	**680**

1 *At December 31, 2010, inventories and supplies related to our chemicals operations have been included with assets held for sale (see Notes 19 and 20).*

4. PROPERTY, PLANT AND EQUIPMENT

	2010			2009		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Canada[1]	8,729	883	7,846	9,664	2,038	7,626
UK	6,610	3,273	3,337	6,115	2,664	3,451
Syncrude	1,545	305	1,240	1,463	270	1,193
US	3,913	2,689	1,224	3,900	2,529	1,371
Yemen	765	727	38	800	728	72
Yemen—Carried Interest	1,614	1,585	29	1,662	1,594	68
Other Countries[2]	1,362	88	1,274	930	99	831
	24,538	9,550	14,988	24,534	9,922	14,612
Energy Marketing	195	66	129	259	83	176
Chemicals[3]	–	–	–	1,135	562	573
Corporate and Other	397	265	132	371	240	131
Total	**25,130**	**9,881**	**15,249**	**26,299**	**10,807**	**15,492**

1 *Includes capitalized costs related to our insitu oil sands (Long Lake and future phases) of $6,179 million (2009—$6,045 million).*
2 *Includes capitalized costs related to Usan development, offshore west Africa of $1,222 million (2009—$779 million).*
3 *Chemicals net book value of $643 million is included in assets held for sale at December 31, 2010 (see Notes 19 and 20).*

Capitalized costs includes $4,514 million (2009—$8,740 million) relating to unproved properties and projects under construction or development. These costs are currently not being depreciated, depleted or amortized and relate to projects under construction and not yet in service such as our Usan development offshore Nigeria, future oil sands phases, shale gas development and suspended exploratory well costs.

DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT

Our DD&A expense for 2010 includes non-cash impairment charges of $93 million on properties in the Gulf of Mexico. In the third quarter, low natural gas prices resulted in impairment on three shelf properties. We impaired two properties during the fourth quarter where declining production performance and higher estimated future abandonment costs reduced the properties' estimated future cash flows.

Our DD&A expense in 2009 included non-cash impairment charges of $78 million at three natural gas properties in Canada and the US Gulf of Mexico. Year-end natural gas proved reserves at these properties were lower as a result of weak natural gas prices throughout 2009. DD&A expense in 2009 also includes $49 million of costs for our Perth discovery in the North Sea, where we expensed allocated acquisition costs as we are unlikely to proceed with development of this prospect.

These properties were written down to their estimated fair value based on their estimated future discounted net cash flows. The estimated future cash flows incorporate a risk-adjusted discount rate and management's estimates of future prices, capital expenditures and production. Based on these significant unobservable inputs, the measurements were considered Level 3 within the fair value hierarchy.

SUSPENDED EXPLORATION WELL COSTS

The following table shows the changes in capitalized exploratory well costs for the two years ended December 31, 2010, and does not include amounts that were initially capitalized and subsequently expensed in the same period. Suspended exploration well costs are included in property, plant and equipment.

	2010	2009
Beginning of Year	794	518
Exploratory Well Costs Capitalized Pending the Determination of Proved Reserves	232	396
Capitalized Exploratory Well Costs Charged to Expense	(14)	(56)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(517)	(21)
Effects of Foreign Exchange Rate Changes	(30)	(43)
End of Year	**465**	**794**

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed as at December 31, 2010.

Aging of Suspended Exploration Wells	United States	Canada	United Kingdom	Nigeria	Total
Less than 1 year	88	4	98	–	190
1–3 years	–	93	4	13	110
4–5 years	111	–	37	–	148
Greater than 5 years	–	–	–	17	17
Total	**199**	**97**	**139**	**30**	**465**

As at December 31, 2010, we have exploratory costs that have been capitalized for more than one year relating to our interests in two exploratory blocks in the Gulf of Mexico ($111 million), certain shale gas and coalbed methane exploratory activities in Canada ($93 million), three exploratory blocks in the UK North Sea ($41 million) and our interest in an exploratory block offshore Nigeria ($30 million). These costs relate to projects with successful exploration wells for which we have not been able to recognize proved reserves. We are assessing all of these wells and projects and are working with our partners to prepare development plans, drill additional appraisal wells or otherwise assess commercial viability.

5. DEFERRED CHARGES AND OTHER ASSETS

	2010	2009
Long-Term Energy Marketing Derivative Contracts (Note 6)	116	225
Defined Benefit Pension Asset (Note 13)	75	60
Long-Term Capital Prepayments	12	27
Other	69	58
Total	**272**	**370**

6. FINANCIAL INSTRUMENTS

Financial instruments carried at fair value on our balance sheet include cash and cash equivalents, restricted cash and derivatives used for trading and non-trading purposes. Our other financial instruments, including accounts receivable, accounts payable, accrued interest payable, dividends payable, short-term borrowings and long-term debt, are carried at cost or amortized cost. The carrying value of our short-term receivables and payables approximates their fair value because the instruments are near maturity.

In our energy marketing group, we enter into contracts to purchase and sell crude oil, natural gas and other energy commodities and use derivative contracts, including futures, forwards, swaps and options, for hedging and trading purposes (collectively derivatives). We also use derivatives to manage commodity price risk and foreign currency risk for non-trading purposes. We categorize our derivative instruments as trading or non-trading activities and carry the instruments at fair value on our balance sheet. The fair values are included with amounts receivable or payable and are classified as long-term or short-term based on anticipated settlement date. Any change in fair value is included in marketing and other income.

We carry our long-term debt at amortized cost using the effective interest rate method. At December 31, 2010, the estimated fair value of our long-term debt was $5,290 million (2009—$7,594 million) as compared to the carrying value of $5,079 million (2009—$7,251 million). The fair value of long-term debt is estimated based on prices provided by quoted markets and third-party brokers.

Derivatives

(A) DERIVATIVE CONTRACTS RELATED TO TRADING ACTIVITIES

During 2010, we sold substantially all of our North American natural gas marketing operations, our oil lease gathering, pipeline and storage assets in North Dakota and Montana and our European gas and power marketing operations, as described in Note 18. Our energy marketing group primarily focuses on our crude oil marketing activities in North America, Europe and Asia.

Our energy marketing group engages in various activities, including the purchase and sale of physical commodities and the use of financial instruments such as commodity and foreign exchange futures, forwards and swaps to economically hedge exposures and generate revenue. These contracts are accounted for as derivatives and, where applicable, are presented net on the balance sheet in accordance with netting arrangements. The fair value and carrying amounts related to derivative instruments held by our energy marketing operations are as follows:

	2010	2009
Commodity Contracts	149	463
Foreign Exchange Contracts	–	3
Accounts Receivable (Note 2)	149	466
Commodity Contracts	116	225
Deferred Charges and Other Assets (Note 5)[1]	116	225
Total Trading Derivative Assets	**265**	**691**
Commodity Contracts	168	410
Foreign Exchange Contracts	–	46
Accounts Payable and Accrued Liabilities (Note 8)	168	456
Commodity Contracts	115	212
Deferred Credits and Other Liabilities (Note 12)[1]	115	212
Total Trading Derivative Liabilities	**283**	**668**
Total Net Trading Derivative Contracts	**(18)**	**23**

1 *These derivative contracts settle beyond 12 months and are considered non-current; once settlement is within 12 months, they are included in accounts receivable or accounts payable.*

Excluding the impact of netting arrangements, the fair value of derivative instruments is as follows:

	2010	2009
Current Trading Assets	467	2,625
Non-Current Trading Assets	156	716
Total Trading Derivative Assets	623	3,341
Current Trading Liabilities	486	2,615
Non-Current Trading Liabilities	155	703
Total Trading Derivative Liabilities	641	3,318
Total Net Trading Derivative Contracts	**(18)**	**23**

Trading revenues generated by our energy marketing group include gains and losses on derivative instruments and non-derivative instruments such as physical inventory. The following trading revenues were recognized in marketing and other income:

	2010	2009
Commodity	342	1,011
Foreign Exchange	(8)	(68)
Marketing Revenue, Net (Note 16)	**334**	**943**

As an energy marketer, we may undertake several transactions during a period to execute a single sale of physical product. Each transaction may be represented by one or more derivative instruments including a physical buy, physical sell, and in many cases, numerous financial instruments for economically hedging and trading purposes. The absolute notional volumes associated with our derivative instrument transactions are as follows:

	2010	2009
Natural Gas *(bcf/d)*	6.5	21.1
Crude Oil *(mmbbls/d)*	3.1	3.5
Power *(GWh/d)*	69.5	217.3
Foreign Exchange *(US$ millions)*	2,457	2,981
Foreign Exchange *(Euro millions)*	53	376

(B) DERIVATIVE CONTRACTS RELATED TO NON-TRADING ACTIVITIES

The fair value and carrying amounts of derivative instruments related to non-trading activities are as follows:

	2010	2009
Accounts Receivable	9	13
Deferred Charges and Other Assets[1]	–	4
Total Non-Trading Derivative Assets	9	17
Accounts Payable and Accrued Liabilities	–	26
Total Non-Trading Derivative Liabilities	–	26
Total Net Non-Trading Derivative Contracts[2]	**9**	**(9)**

1 These derivative contracts settle beyond 12 months and are considered non-current.

2 The net fair value of these derivatives is equal to the gross fair value before consideration of netting arrangements and collateral posted or received with counterparties.

Crude oil put options

During 2010, we purchased put options on 100,000 bbls/d of our 2011 crude oil production. These options establish a monthly WTI floor price of between US$50/bbl and US$63/bbl and provide a base level of price protection without limiting our upside to higher prices. The options settle monthly and unexpired options are recorded at fair value throughout their term. As a result, changes in forward crude oil prices created gains or losses on these options at each period end. The put options were purchased for $33 million and are carried at fair value. As at December 31, 2010 the fair value of the options was approximately $9 million and we recorded a fair value loss of $24 million in the year.

In 2009, we purchased put options on 90,000 bbls/d of our 2010 crude oil production. These options were purchased for $39 million and established a WTI floor price of US$50/bbl on these volumes. At December 31, 2009, higher crude oil prices reduced the fair value of the options to $17 million and we recorded a fair value loss of $22 million in 2009. Strengthening crude oil prices in 2010 reduced the fair value of these options to nil and we recorded a fair value loss of $17 million in 2010.

In 2008, we purchased put options on approximately 70,000 bbls/d of our 2009 crude oil production. These options were purchased for $14 million and established an annual Dated Brent floor price of US$60/bbl on these volumes. At December 31, 2008, the put options had an estimated fair value of $233 million due to lower crude oil prices. Strengthening crude oil prices in 2009 reduced the fair value of these options to nil and we recorded a fair value loss of $229 million in 2009.

The crude oil put options are carried at fair value and are classified as long-term or short-term based on their anticipated settlement date. Fair value of the put options is supported by multiple quotes obtained from third-party brokers, which were validated with observable market data to the extent possible. Any change in fair value is included in marketing and other income.

	December 31, 2010				
	Notional Volumes *(bbls/d)*	Term	Average Floor Price *(US$/bbl)*	Fair Value *(Cdn$ millions)*	Change in Fair Value *(Cdn$ millions)*
WTI Crude Oil Put Options (monthly)	100,000	2011	56	9	(24)

	December 31, 2009				
	Notional Volumes *(bbls/d)*	Term	Average Floor Price *(US$/bbl)*	Fair Value *(Cdn$ millions)*	Change in Fair Value *(Cdn$ millions)*
WTI Crude Oil Put Options (monthly)	60,000	2010	50	13	(12)
WTI Crude Oil Put Options (annual)	30,000	2010	50	4	(10)
				17	(22)

(C) FAIR VALUE OF DERIVATIVES

For purposes of estimating the fair value of our derivative contracts, wherever possible, we utilize quoted market prices and, if not available, estimates from third-party brokers. These broker estimates are corroborated with multiple sources and/or other observable market data utilizing assumptions that market participants would use when pricing the asset or liability, including assumptions about risk and market liquidity. Inputs to fair valuations may be readily observable, market-corroborated or generally unobservable. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. To value longer-term transactions and transactions in less active markets for which pricing information is not generally available, unobservable inputs may be used.

We classify the fair value of our derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments.

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 consists of financial instruments such as exchange-traded derivatives, and we use information from markets such as the New York Mercantile Exchange.
- Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reported date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. We obtain information from sources such as the Natural Gas Exchange (formerly Netthruput), independent price publications and over-the-counter broker quotes.
- Level 3—Valuations in this level are those with inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value. Level 3 instruments may include items based on pricing services or broker quotes where we are unable to verify the observability of inputs into their prices. Level 3 instruments include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods.

The following table includes our derivatives that are carried at fair value for our trading and non-trading activities as at December 31, 2010 and 2009. Financial assets and liabilities are classified in the fair value hierarchy in their entirety based on the least observable input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

Net Derivatives at December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Total**
Trading Derivatives (Commodity Contracts)	(17)	(18)	17	(18)
Non-Trading Derivatives	–	9	–	9
Total	**(17)**	**(9)**	**17**	**(9)**

Net Derivatives at December 31, 2009	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity Contracts	(143)	167	42	66
Foreign Exchange Contracts	–	(43)	–	(43)
Trading Derivatives	(143)	124	42	23
Non-Trading Derivatives	–	(9)	–	(9)
Total	**(143)**	**115**	**42**	**14**

A reconciliation of changes in the fair value of our derivatives classified as Level 3 for the years ended December 31, 2010 and 2009 is provided below:

	2010	**2009**
Level 3 Net Derivatives at January 1	**42**	**(82)**
Realized and unrealized gains (losses)	19	74
Purchases	–	4
Settlements	(44)	54
Transfers into Level 3	–	–
Transfers out of Level 3	–	(8)
Level 3 Net Derivatives at December 31	**17**	**42**
Unsettled gains (losses) relating to instruments still held as of December 31	19	66

Items classified in Level 3 are generally economically hedged such that gains or losses on positions classified in Level 3 are often offset by gains or losses on positions classified in Level 1 or 2. Transfers into or out of Level 3 represent existing assets and liabilities that were either previously categorized as a higher level for which the inputs became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Fair values of instruments in Level 3 are determined using broker quotes, pricing services and internally-developed inputs. We performed a sensitivity analysis of inputs used to calculate the fair value of Level 3 instruments. Using reasonably possible alternative assumptions, the fair value of Level 3 instruments at December 31, 2010 would change by $5 million.

7. RISK MANAGEMENT

(A) MARKET RISK

We invest in significant capital projects, purchase and sell commodities, issue short-term borrowings and long-term debt, and invest in foreign operations. These activities expose us to market risks from changes in commodity prices, foreign currency rates and interest rates, which could affect our earnings and the value of the financial instruments we hold. We use derivatives for trading and non-trading purposes as part of our overall risk management policy to manage these market risk exposures.

The following market risk discussion relates primarily to commodity price risk and foreign currency risk related to our financial instruments as our exposure to interest rate risk is immaterial given that the majority of our debt is fixed rate.

Commodity price risk

We are exposed to commodity price movements as part of our normal oil and gas operations, particularly in relation to the prices received for our crude oil and natural gas. Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Changes in crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, these changes also may affect the value of our oil and gas properties, our level of spending for exploration and development, and our ability to meet our obligations as they come due.

The majority of our oil and gas production is sold under short-term contracts, exposing us to the risk of near-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. We actively manage these risks by using derivative contracts such as commodity put options.

Our energy marketing business is focused on maximizing the value of our equity production and, to a lesser extent, providing services to customers and suppliers to meet their energy commodity needs. We primarily market and trade physical crude oil in selected regions of the world. We accomplish this by buying and selling physical commodities, by acquiring and holding rights to physical transportation and storage assets for these commodities, and by building strong relationships with our customers and suppliers. Prior to the related disposition in 2010, we also marketed and traded physical natural gas, electricity and other commodities. In order to manage the commodity and foreign exchange price risks that come from this physical business, we use financial derivative contracts, including energy-related futures, forwards, swaps and options, as well as currency swaps or forwards.

Our risk management activities make use of tools such as Value-at-Risk (VaR) and stress testing. VaR is a statistical estimate of the expected profit or loss of a portfolio of positions assuming normal market conditions. We use a 95% confidence interval and an assumed two-day holding period in our measure, although actual results can differ from this estimate in abnormal market conditions or if positions are held longer than two days based on market views or a lack of market liquidity to exit them. We estimate VaR primarily by using the Variance-Covariance method based on historical commodity price volatility and correlation inputs where available and by historical simulation in other situations. Our estimate is based upon the following key assumptions:

- changes in commodity prices are either normally or "T" distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

We have defined VaR limits for different segments of our energy marketing business. These limits are calculated on an economic basis and include physical and financial derivatives, as well as physical transportation and storage capacity contracts accounted for as executory contracts in our financial statements. We monitor our positions against these VaR limits daily. Our year-end, annual high, annual low and average VaR amounts are as follows:

Value-at-Risk *(Cdn$ millions)*	**2010**	**2009**
Year-End	11	11
High	15	24
Low	4	9
Average	10	15

If a market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. We perform stress tests on a regular basis to complement VaR and assess the impact of abnormal changes in prices on our positions.

Foreign currency risk

Foreign currency risk is created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates. A substantial portion of our activities are transacted in or referenced to US dollars, including:

- sales of crude oil and natural gas products;
- capital spending and expenses for our oil and gas operations;
- commodity derivative contracts used primarily by our energy marketing group; and
- short-term borrowings and long-term debt.

We manage our exposure to fluctuations between the US and Canadian dollar by maintaining our expected net cash flows and borrowings in the same currency. Cash inflows generated by our foreign operations and borrowings on our US-dollar debt facilities are generally used to fund US-dollar capital expenditures and debt repayments. We maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows.

We designate most of our US-dollar borrowings as a hedge against our US-dollar net investment in self-sustaining foreign operations. The foreign exchange gains or losses related to the effective portion of our designated US-dollar debt are included in accumulated other comprehensive income in equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31, 2010 and 2009 are as follows:

(US$ millions)	**December 31, 2010**	**December 31, 2009**
Net Investment in Self-Sustaining Foreign Operations	4,443	4,492
Designated US-Dollar Debt	4,393	4,492

For the year ended December 31, 2010, the undesignated portion of our US-dollar debt resulted in a net foreign exchange loss of $3 million ($3 million, net of income tax expense) and is included in marketing and other income (2009—$151 million ($132 million, net of income tax expense)). A one-cent change in the US dollar to Canadian dollar exchange rate would increase or decrease our accumulated other comprehensive income by approximately $38 million, net of income tax, and would increase or decrease our net income by approximately $3 million, net of income tax.

We also have exposures to currencies other than the US dollar, including a portion of our UK operating expenses, capital spending and future asset retirement obligations, which are denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies. In our energy marketing group, we enter into transactions in various currencies, including Canadian and US dollars, British pounds and Euros. We actively manage significant currency exposures using forward contracts and swaps.

(B) CREDIT RISK

Credit risk affects our oil and gas operations and our energy marketing activities, and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the energy industry, including integrated oil companies, refiners and utilities, and are subject to normal industry credit risk. Over 80% of our exposure is with these large energy companies. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We take the following measures to reduce this risk:

- assess the financial strength of our counterparties through a rigorous credit analysis process;
- limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Executive Risk Management Committee and the Finance Committee of the board;
- set counterparty credit limits based on rating agency credit ratings and internal assessments of company and industry analysis;
- review counterparty credit limits regularly; and
- use standard agreements where possible that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk; however, there can be no assurance that these processes will protect us against all losses from non-performance.

At December 31, 2010, three counterparties individually made up more than 10% of our credit exposure. These counterparties are major integrated oil companies with strong investment-grade ratings. Two other counterparties made up more than 5% of our credit exposure.

The following table illustrates the composition of credit exposure by credit rating:

Credit Rating	2010	2009
A or higher	71%	67%
BBB	20%	26%
Non-Investment Grade	9%	7%
Total	**100%**	**100%**

Our maximum counterparty credit exposure at the balance sheet date consists primarily of the carrying amounts of non-derivative financial assets such as cash and cash equivalents, restricted cash, accounts receivable, as well as the fair value of derivative financial assets. We have provided an allowance of $44 million for credit risk with our counterparties. In addition, we incorporate the credit risk associated with counterparty default, as well as Nexen's own credit risk, into our estimates of fair value.

Collateral received from customers at December 31, 2010 includes $38 million of cash and $104 million of letters of credit. The cash received is included in accounts payable and accrued liabilities.

(C) LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations as they fall due. We require liquidity specifically to fund capital requirements, satisfy financial obligations as they become due and to operate our energy marketing business. We generally rely on operating cash flows to provide liquidity and we also maintain significant undrawn committed credit facilities. At December 31, 2010, we had $4 billion of cash and available undrawn committed lines of credit. This includes $1 billion of cash and cash equivalents on hand and undrawn committed term credit facilities of $3 billion, of which $322 million was supporting letters of credit at December 31, 2010. Our committed term credit facilities are available until 2014 unless extended. We also have $464 million of undrawn, uncommitted credit facilities, of which $112 million was supporting letters of credit at year end.

The following table details the contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2010:

	December 31, 2010				
	Total	**< 1 Year**	**1–3 Years**	**4–5 Years**	**> 5 Years**
Long-Term Debt (Note 9)	5,171	–	497	249	4,425
Cumulative Interest on Long-Term Debt[1]	7,286	336	670	612	5,668
Total	**12,457**	**336**	**1,167**	**861**	**10,093**

1 At December 31, 2010 none of our variable interest rate debt was drawn.

The following table details contractual maturities for our derivative financial liabilities. The balance sheet amounts for derivative financial liabilities included below are not materially different from the contractual amounts due on maturity.

	December 31, 2010				
	Total	**< 1 Year**	**1–3 Years**	**4–5 Years**	**> 5 Years**
Trading Derivatives (Note 6)	**283**	**168**	**105**	**5**	**5**

At December 31, 2010, the collateral we have posted with counterparties includes $4 million of cash and $185 million of letters of credit related to our trading activities. Cash posted is included with our accounts receivable. Cash collateral is not normally applied to contract settlement. Once a contract has been settled, the collateral amounts are refunded. In the event of a default, the cash would likely be retained.

The commercial agreements our energy marketing group enters into often include financial assurance provisions that allow us and our counterparties to effectively manage credit risk. The agreements can require collateral to be posted if an adverse credit-related event occurs, such as a drop in credit ratings to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral secures the payment of such amounts. We have significant undrawn credit facilities and cash to fund these potential collateral requirements.

Our exchange-traded derivative contracts are also subject to margin requirements. We have margin deposits of $40 million (2009—$198 million), which have been included in restricted cash.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2010	**2009**
Energy Marketing Payables	1,015	1,366
Energy Marketing Derivative Contracts (Note 6)	168	456
Accrued Payables	676	619
Trade Payables	164	210
Income Taxes Payable	345	179
Stock-Based Compensation	30	72
Other	147	136
Total[1]	**2,545**	**3,038**

1 At December 31, 2010, accounts payable and accrued liabilities related to our chemical operations have been included in liabilities held for sale (see Notes 19 and 20).

9. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

	2010	2009
Canexus Term Credit Facilities, due 2012[1]	–	233
Canexus Notes, due 2013[1]	–	52
Notes, due 2013 (US$500 million) (A)	497	523
Term Credit Facilities, due 2014 (B)	–	1,570
Canexus Convertible Debentures, due 2014[1]	–	46
Notes, due 2015 (US$250 million) (C)	249	262
Notes, due 2017 (US$250 million) (D)	249	262
Notes, due 2019 (US$300 million) (E)	298	314
Notes, due 2028 (US$200 million) (F)	199	209
Notes, due 2032 (US$500 million) (G)	497	523
Notes, due 2035 (US$790 million) (H)	786	827
Notes, due 2037 (US$1,250 million) (I)	1,243	1,308
Notes, due 2039 (US$700 million) (J)	696	733
Subordinated Debentures, due 2043 (US$460 million) (K)	457	481
	5,171	7,343
Unamortized Discount and Debt Issue Costs	(92)	(92)
Total	**5,079**	**7,251**

1 *Included in liabilities held for sale at December 31, 2010 (see Notes 19 and 20).*

(A) NOTES, DUE 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05% and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.2%.

(B) TERM CREDIT FACILITIES

We have unsecured term credit facilities of $3 billion (US$3 billion) available until July 2014, none of which were drawn at December 31, 2010 (2009—$1.6 billion (US$1.5 billion)). Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable at floating rates. During 2010, the weighted-average interest rate was 1.6% (2009—1.0%). At December 31, 2010, $322 million (US$324 million) of these facilities was utilized to support outstanding letters of credit (2009—$407 million (US$389 million)).

(C) NOTES, DUE 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.2% and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.15%.

(D) NOTES, DUE 2017

During May 2007, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.65% and the principal is to be repaid in May 2017. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(E) NOTES, DUE 2019

During July 2009, we issued US$300 million of notes. Interest is payable semi-annually at a rate of 6.2% and the principal is to be repaid in July 2019. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.40%.

(F) NOTES, DUE 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.25%.

(G) NOTES, DUE 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.375%.

(H) NOTES, DUE 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875% and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.20%.

(I) NOTES, DUE 2037

During May 2007, we issued US$1,250 million of notes. Interest is payable semi-annually at a rate of 6.4% and the principal is to be repaid in May 2037. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.35%.

(J) NOTES, DUE 2039

During July 2009, we issued US$700 million of notes. Interest is payable semi-annually at a rate of 7.5% and the principal is to be repaid in July 2039. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term-to-maturity equal to the remaining term of the notes plus 0.45%.

(K) SUBORDINATED DEBENTURES, DUE 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(L) LONG-TERM DEBT REPAYMENTS

The following schedule outlines the required timetable of debt repayments and does not preclude earlier repayments as per the provisions of the respective notes.

2011	–
2012	–
2013	497
2014	–
2015	249
Thereafter	4,425
Total[1]	**5,171**

1 *Excludes repayments related to our chemical operations (see Notes 19 and 20).*

(M) DEBT COVENANTS

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2010 and 2009, we were in compliance with all covenants.

(N) SHORT-TERM BORROWINGS

Nexen has uncommitted, unsecured credit facilities of approximately $464 million (US$467 million), (2009—$492 million (US$470 million)), none of which were drawn at either December 31, 2010 or 2009. We utilized $112 million (US$112 million) of these facilities to support outstanding letters of credit at December 31, 2010 (2009—$86 million (US$82 million)). Interest is payable at floating rates. During 2010, the weighted-average interest rate on our short-term borrowings was 0.9% (2009—2.1%).

(O) INTEREST EXPENSE

	2010	2009	2008
Long-Term Debt	361	360	303
Other	29	17	19
Total	390	377	322
Less: Capitalized	(80)	(72)	(240)
Total[1]	**310**	**305**	**82**

1 *Excludes interest expense related to our chemical operations (see Notes 19 and 20).*

Capitalized interest relates to and is included as part of the cost of oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings. In 2009, we ceased capitalizing interest on Phase 1 of Long Lake.

10. CAPITAL DISCLOSURE

Our objective for managing our capital structure is to ensure that we have the financial capacity, liquidity and flexibility to fund our investment in full-cycle exploration and development of conventional and unconventional resources and for energy marketing activities. We generally rely on operating cash flows to fund capital investments. However, given the long cycle-time of some of our development projects, which require significant capital investment prior to cash flow generation, and volatile commodity prices, it is not unusual for capital expenditures to exceed our cash flow from operating activities in any given period. As such, our financing needs depend on the timing of expected net cash flows in a particular development or commodity cycle. This requires us to maintain financial flexibility and liquidity. Our capital management policies are aimed at:

- maintaining an appropriate balance between short-term borrowings, long-term debt and equity;
- maintaining sufficient undrawn committed credit capacity to provide liquidity;
- ensuring ample covenant room, permitting us to draw on credit lines as required; and
- ensuring we maintain a credit rating that is appropriate for our circumstances.

We have the ability to make adjustments to our capital structure by issuing additional equity or debt, returning cash to shareholders and making adjustments to our capital investment programs. Our capital consists of equity, short-term borrowings, long-term debt, and cash and cash equivalents as follows:

Net Debt[1]	2010	2009
Long-Term Debt	5,079	7,251
Less: Cash and Cash Equivalents	(1,005)	(1,700)
Total[2]	**4,074**	**5,551**
Equity[3]	**8,707**	**7,582**

1 *Includes all of our borrowings and is calculated as long-term debt and short-term borrowings less cash and cash equivalents.*
2 *December 31, 2010 excludes Net Debt related to our chemical operations that are included in assets and liabilities held for sale (see Notes 19 and 20).*
3 *Equity is the historical issue of equity and accumulated retained earnings.*

We monitor the leverage in our capital structure by reviewing the ratio of net debt to cash flow from operating activities and interest coverage ratios at various commodity prices.

We use the ratio of net debt to cash flow from operating activities as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is a non-GAAP measure that does not have any standard meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by others. We calculate net debt using the GAAP measures of long-term debt and short-term borrowings less cash and cash equivalents (excluding restricted cash).

For the 12 months ended December 31, 2010, the net debt to cash flow from operating activities ratio (before changes in non-cash working capital and other) was 1.9 times compared to 2.5 times at December 31, 2009. While we typically expect the target ratio to fluctuate between 1.0 and 2.0 times under normalized commodity prices, this can be higher or lower depending on commodity price volatility, where we are in the investment cycle or when we identify strategic opportunities requiring additional investment. Whenever we exceed our target ratio, we assess whether we need to develop a strategy to reduce our leverage and lower this ratio back to target levels over time.

Our interest coverage ratio monitors our ability to fund the interest requirements associated with our debt. Our interest coverage increased from 8.5 times at the end of 2009 to 9.3 times at December 31, 2010. Interest coverage is calculated by dividing our twelve-month trailing earnings before interest, taxes, DD&A, exploration expense and other non-cash items (adjusted EBITDA) by interest expense before capitalized interest. Adjusted EBITDA is a non-GAAP measure that is calculated using net income excluding interest expense, provision for income taxes, exploration expense, DD&A, impairment and other non-cash expenses. The calculation of adjusted EBITDA is set out in the following table and is unlikely to be comparable to similar measures presented by others:

	2010	2009
Net Income Attributable to Nexen Inc.	1,197	536
Add:		
Interest Expense	310	305
Provision for Income Taxes	554	246
Depreciation, Depletion, Amortization and Impairment	1,662	1,615
Exploration Expense	328	302
Recovery of Non-Cash Stock-Based Compensation	(41)	(10)
Change in Fair Value of Crude Oil Put Options	41	251
Items Related to Discontinued Operations	(475)	–
Other Non-Cash Items	50	72
Adjusted EBITDA	**3,626**	**3,317**

11. ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our PP&E are as follows:

	2010	2009
Asset Retirement Obligations, Beginning of Year	1,053	1,059
Obligations Incurred with Development Activities	32	27
Obligations Settled	(43)	(42)
Accretion Expense	66	70
Revisions to Estimates	169	13
Obligations Related to Dispositions[1]	(166)	–
Effects of Changes in Foreign Exchange Rate	(47)	(74)
End of Year [2, 3]	**1,064**	**1,053**

1 *Includes obligations associated with discontinued operations of $163 million.*

2 *Obligations due within 12 months of $55 million (2009—$35 million) have been included in accounts payable and accrued liabilities.*

3 *Obligations relating to our oil and gas activities amount to $1,064 million (2009—$1,002 million), and obligations relating to our chemicals business amount to nil (2009—$51 million). At December 31, 2010, asset retirement obligations associated with our chemicals business are included in liabilities held for sale (see Note 20).*

Our total estimated undiscounted inflated asset retirement obligations amount to $2,552 million (2009—$2,341 million). We discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 6% (2009—5.9%). Approximately $306 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

12. DEFERRED CREDITS AND OTHER LIABILITIES

	2010	2009
Deferred Tax Credit	367	503
Long-Term Marketing Derivative Contracts (Note 6)	115	212
Defined Benefit Pension Obligations (Note 13)	75	74
Capital Lease Obligations	42	61
Deferred Transportation Revenue	–	55
Other	97	116
Total	**696**	**1,021**

During 2008, we completed an internal reorganization and financing of our assets in the North Sea, which provided us with an additional one-time tax deduction in the UK. As these transactions were completed within our consolidated group, we are unable to recognize the benefit of the tax deductions until the assets are recognized in income by way of a sale to a third party or depletion through use. At December 31, 2010, we deferred recognizing $367 million (2009—$503 million) of tax credits in net income.

13. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, as well as other post-retirement benefit programs, which cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our proportionate share of this plan.

(A) DEFINED BENEFIT PENSION PLANS

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds. The supplemental plan is not tax-efficient to fund. Instead, obligations are secured by an irrevocable letter of credit.

	2010				
	Nexen			Syncrude	Total
	Registered (Funded)	Supplemental[1] (Unfunded)	Total		
Change in Projected Benefit Obligation (PBO)					
Beginning of Year	243	76	319	125	444
Service Cost	17	4	21	5	26
Interest Cost	15	5	20	7	27
Plan Participants' Contributions	6	–	6	1	7
Actuarial Loss/(Gain)	26	15	41	19	60
Benefits Paid	(16)	(3)	(19)	(6)	(25)
End of Year[1, 2]	**291**	**97**	**388**	**151**	539
Change in Fair Value of Plan Assets					
Beginning of Year	264	–	264	69	333
Actual Return on Plan Assets	28	–	28	8	36
Employer's Contribution	30	3	33	14	47
Plan Participants' Contributions	6	–	6	1	7
Benefits Paid	(16)	(3)	(19)	(5)	(24)
End of Year	**312**	**–**	**312**	**87**	399
Reconciliation of Funded Status					
Funded Status[1]	21	(97)	(76)	(64)	(140)
Items Not Yet Recognized in Earnings					
Unamortized Prior Service Costs	1	(1)	–	–	–
Unamortized Net Actuarial Loss	53	32	85	52	137
Net Recognized Pension Asset (Liability)	**75**	**(66)**	**9**	**(12)**	(3)
Accounts Recorded in the Consolidated Balance Sheet					
Deferred Charges and Other Assets (Note 5)	75	–	75	–	75
Accounts Payable and Accrued Liabilities	–	(3)	(3)	–	(3)
Deferred Credits and Other Liabilities (Note 12)	–	(63)	(63)	(12)	(75)
Net Recognized Pension Asset (Liability)	**75**	**(66)**	**9**	**(12)**	(3)
Assumptions (%)					
Accrued Benefit Obligation at December 31					
Discount Rate	5.25	5.25		5.25	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		4.45	
Benefit Cost for Year Ended December 31					
Discount Rate	6.00	6.00		6.00	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		4.45	
Long-Term Annual Rate of Return on Plan Assets	7.00	–		7.50	

	2009				
	Nexen			Syncrude	Total
	Registered (Funded)	Supplemental[1] (Unfunded)	Total		
Change in Projected Benefit Obligation (PBO)					
Beginning of Year	203	62	265	107	372
Service Cost	14	4	18	5	23
Interest Cost	14	4	18	7	25
Plan Participants' Contributions	6	–	6	1	7
Actuarial Loss/(Gain)	16	8	24	10	34
Benefits Paid	(10)	(2)	(12)	(5)	(17)
End of Year[1,2]	**243**	**76**	**319**	**125**	**444**
Change in Fair Value of Plan Assets					
Beginning of Year	153	–	153	57	210
Actual Return on Plan Assets	40	–	40	9	49
Employer's Contribution	75	2	77	7	84
Plan Participants' Contributions	6	–	6	1	7
Benefits Paid	(10)	(2)	(12)	(5)	(17)
End of Year	**264**	**–**	**264**	**69**	**333**
Reconciliation of Funded Status					
Funded Status[1]	21	(76)	(55)	(56)	(111)
Items Not Yet Recognized in Earnings					
Unamortized Prior Service Costs	2	(1)	1	–	1
Unamortized Net Actuarial Loss	37	18	55	39	94
Net Recognized Pension Asset (Liability)	**60**	**(59)**	**1**	**(17)**	**(16)**
Accounts Recorded in the Consolidated Balance Sheet					
Deferred Charges and Other Assets (Note 5)	60	–	60	–	60
Accounts Payable and Accrued Liabilities	–	(2)	(2)	–	(2)
Deferred Credits and Other Liabilities (Note 12)	–	(57)	(57)	(17)	(74)
Net Recognized Pension Asset (Liability)	**60**	**(59)**	**1**	**(17)**	**(16)**
Assumptions (%)					
Accrued Benefit Obligation at December 31					
Discount Rate	6.00	6.00		6.00	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		5.00	
Benefit Cost for Year Ended December 31					
Discount Rate	6.50	6.50		6.50	
Long-Term Rate of Employee Compensation Increase	4.00	4.00		5.00	
Long-Term Annual Rate of Return on Plan Assets	7.00	–		8.50	

1 *Includes self-funded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. The self-funded obligations for supplemental benefits are backed by an irrevocable letter of credit.*

2 *The accumulated benefit obligations (the projected benefit obligation excluding future salary increases) of the Nexen plan was $256 million at December 31, 2010, (2009—$211 million). Nexen's supplemental pension plan's accumulated benefit obligation was $78 million at December 31, 2010 (2009—$65 million). Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $120 million at December 31, 2010 (2009—$96 million).*

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2010	2009	2008
Nexen			
Cost of Benefits Earned by Employees	21	18	23
Interest Cost on Benefits Earned	20	18	17
Actual (Return) Loss on Plan Assets	(28)	(40)	54
Actuarial (Gains)/Losses	41	24	(39)
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	54	20	55
Difference Between Actual and Expected Return on Plan Assets	8	26	(71)
Difference Between Actual and Recognized Actuarial Losses	(38)	(21)	41
Difference Between Actual and Recognized Past Service Costs	1	–	1
Net Pension Expense	**25**	**25**	**26**
Syncrude[1]			
Cost of Benefits Earned by Employees	5	5	4
Interest Cost on Benefits Earned	7	7	7
Actual (Return) Loss on Plan Assets	(8)	(9)	19
Actuarial (Gains)/Losses	19	10	(25)
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	23	13	5
Difference Between Actual and Expected Return on Plan Assets	2	4	(26)
Difference Between Actual and Recognized Actuarial Losses	(16)	(8)	27
Net Pension Expense	**9**	**9**	**6**
Total Net Pension Expense[2]	**34**	**34**	**32**

1 *Nexen's share of Syncrude's plan.*
2 *Pension expense is reported principally within operating expense and general and administrative expense in the Consolidated Statement of Income.*

(B) PLAN ASSET ALLOCATION AT DECEMBER 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committee of Nexen. Nexen's investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's investment policies.

Nexen's investment strategy is to ensure appropriate diversification between and within asset classes in order to optimize the return/risk trade-off. Nexen's policy allows investment in equities, fixed income, cash and real estate assets. Derivative instruments can be utilized as deemed appropriate by the Pension Committee. Nexen's expected long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities. The returns that are used as the basis for future expectations are derived from the major asset categories in which Nexen is currently invested.

The target allocations for plan assets are identified in the table below. Equity securities primarily include investments in large-cap companies, both Canadian and foreign, and debt securities primarily include corporate bonds of companies from diversified industries and Canadian Treasury issuances. The Canadian fixed income pooled funds invest in low-cost fixed income index funds that track the DEX Universe Bond Index. The Canadian equity pooled funds invest in low-cost equity index funds that track the S&P/TSX Composite Index. The foreign equity pooled funds invest in low-cost equity index funds that track the S&P 500 and the MSCI EAFE Indexes.

Nexen also has an unregistered self-funded supplemental benefits pension plan that covers obligations that are limited by statutory guidelines. These benefits are backed by an irrevocable letter of credit and payments are made from Nexen's general operating revenues.

Syncrude's pension plans are governed and administered separately from Nexen's. Syncrude's investment assets are subject to similar investment goals, policies and strategies.

Plan Asset Allocation *(%)*	**Expected 2011**	**2010**	**2009**
Nexen			
Equity Securities	65	65	62
Debt Securities	35	35	38
Total	**100**	**100**	**100**
Syncrude			
Equity Securities	60	60	71
Debt Securities	40	40	29
Total	**100**	**100**	**100**

The fair values of Nexen's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

	Fair Value Measurements at December 31, 2010			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Asset Category				
Cash	3	–	–	3
Pooled Funds				
Canadian Fixed Income	–	105	–	105
Canadian Equity	–	78	–	78
Foreign Equity	–	126	–	126
Total	**3**	**309**	**–**	**312**

The fair values of Nexen's defined benefit pension plan assets at December 31, 2009 by asset category are as follows:

	Fair Value Measurements at December 31, 2009			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Asset Category				
Cash	9	–	–	9
Equity Securities				
Canadian Equity	36	–	–	36
Pooled Funds				
Canadian Fixed Income	–	90	–	90
Canadian Equity	–	30	–	30
Foreign Equity	–	99	–	99
Total	**45**	**219**	**–**	**264**

The fair values of Syncrude's defined benefit pension plan assets at December 31, 2010 by asset category are as follows:

	Fair Value Measurements at December 31, 2010			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Asset Category				
Cash	1	–	–	1
Pooled Funds				
Canadian Fixed Income	–	32	–	32
Canadian Equity	–	22	–	22
Foreign Equity	–	31	–	31
Other Types of Investment				
Other	–	–	1	1
Total	**1**	**85**	**1**	87

The fair values of Syncrude's defined benefit pension plan assets at December 31, 2009 by asset category are as follows:

	Fair Value Measurements at December 31, 2009			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Asset Category				
Cash	1	–	–	1
Pooled Funds				
Canadian Fixed Income	–	17	–	17
Canadian Equity	–	19	–	19
Foreign Equity	–	30	–	30
Other Types of Investment				
Other	–	–	2	2
Total	**1**	**66**	**2**	69

(C) DEFINED CONTRIBUTION PENSION PLANS

Under these plans, pension benefits are based on plan contributions. During 2010, Canadian pension expense for these plans was $7 million (2009—$8 million; 2008—$6 million). During 2010, US pension expense for these plans was $6 million (2009—$7 million; 2008—$4 million) and UK pension expense for these plans was $6 million (2009—$6 million; 2008—$6 million).

(D) POST-RETIREMENT BENEFITS

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependants. The present value of Nexen employees' future post-retirement benefits at December 31, 2010 was $15 million (2009—$14 million).

(E) EMPLOYER FUNDING CONTRIBUTIONS AND BENEFIT PAYMENTS

Canadian regulators have prescribed funding requirements for Nexen's defined benefit plans. Funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law to ensure the plans are adequately funded in light of expected future changes in assumptions. For our defined contribution plans, we make contributions on behalf of our employees and no further obligation exists. Funding contributions related to our defined benefit plans are:

	Expected 2011	2010	2009
Nexen	11	33	77
Syncrude	14	14	7
Total Defined Benefit Contributions	**25**	**47**	**84**

Our most recent funding valuation was prepared as of June 30, 2010. Our next funding valuation is required by June 30, 2013. Syncrude's most recent funding valuation was prepared as of December 31, 2009. The next funding valuation is required as at December 31, 2012.

Our total benefit payments in 2010 were $19 million for Nexen (2009—$12 million). Our share of Syncrude's total benefit payments in 2010 was $6 million (2009—$5 million). Our estimated future payments are as follows:

	Defined Benefit		Other	
	Nexen	Syncrude	Nexen	Syncrude
2011	12	6	3	–
2012	12	6	4	–
2013	13	6	4	–
2014	14	7	4	–
2015	14	7	5	–
2016–2020	84	45	28	2

14. EQUITY

(A) AUTHORIZED CAPITAL

Authorized share capital consists of an unlimited number of common shares of no par value and an unlimited number of Class A preferred shares of no par value, issuable in series.

(B) ISSUED COMMON SHARES AND DIVIDENDS

(thousands of shares)	2010	2009	2008
Issued Common Shares, Beginning of Year	522,916	519,449	528,305
Issue of Common Shares for Cash			
Exercise of Tandem Options	527	1,146	1,911
Dividend Reinvestment Plan	1,654	1,328	871
Employee Flow-through Shares	609	993	499
Repurchased under Normal Course Issuer Bid	–	–	(12,137)
End of Year	**525,706**	**522,916**	**519,449**
Dividends Declared per Common Share *($/share)*	**0.20**	**0.20**	**0.18**
Cash Consideration *(Cdn$ millions)*			
Exercise of Tandem Options	5	12	23
Dividend Reinvestment Plan	35	29	25
Employee Flow-through Shares	15	16	16
Total	**55**	**57**	**64**

During the year 1,654,173 common shares were issued under the Dividend Reinvestment Plan, leaving a balance of 621,171 common shares (2009—2,275,344; 2008—3,603,841) reserved for issuance at December 31, 2010. In 2011, we plan to request board approval to increase the number of common shares reserved for issuance under the Dividend Reinvestment Plan. Dividends paid to holders of common shares have been designated as "eligible dividends" for Canadian tax purposes.

During 2008, we received approval from the Toronto Stock Exchange (TSX) for a Normal Course Issuer Bid to repurchase up to a maximum of 52,914,046 common shares between August 6, 2008 and August 5, 2009. Under this authorization, we repurchased and cancelled 12,136,900 common shares acquired on the open market through the TSX in 2008 at an average price of $27.85 per common share, totalling $338 million. Of the amount paid, $22 million reduced the book value of our common shares and the excess of $316 million reduced retained earnings. We did not repurchase any common shares in 2010 or 2009.

(C) TANDEM OPTIONS

In 2010, our board of directors approved amendments to our tandem option plans to allow for performance vesting of certain grants. Performance tandems vest over three years if our annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to our industry peer group. The ultimate number of performance tandems that vest will depend upon our performance measured over three calendar years. If our performance is below the specified level compared with our industry peer group, the performance tandems awarded will be forfeited. If our performance is at or above the specified level, the number of performance tandems exercisable shall be determined by our relative ranking. Stock compensation expense related to the performance tandems is accrued based on the price of our common shares at the end of the period and the anticipated performance factor. The expense is recognized over a three-year graded vesting period similar to the existing tandems plan.

We grant tandem and performance tandem options to purchase common shares to officers and employees. Performance tandems are awarded to officers and senior employees. Each option permits the right to either purchase one Nexen common share at the exercise price or receive a cash payment equal to the excess of market price over the exercise price. There were no performance tandems exercised during the year ended December 31, 2010. The following tandem options have been granted:

	2010		2009		2008	
(thousands of shares)	**Options** *(thousands)*	**Weighted Average Exercise Price** *($/option)*	**Options** *(thousands)*	**Weighted Average Exercise Price** *($/option)*	**Options** *(thousands)*	**Weighted Average Exercise Price** *($/option)*
Outstanding Tandem Options, Beginning of Year	23,130	25	24,622	22	27,403	20
Granted	4,615[1]	22	4,350	24	3,534	19
Exercised for Stock	(527)	9	(1,146)	10	(1,911)	13
Surrendered for Cash	(2,191)	11	(4,116)	12	(3,839)	13
Cancelled	(2,704)	28	(560)	28	(552)	30
Expired	(3,888)	27	(20)	12	(13)	11
End of Year	**18,435**	**25**	**23,130**	**25**	**24,622**	**22**
Tandem Options Exercisable at End of Year	9,949	27	15,282	25	17,087	21
Common Shares Reserved for Issuance Under the Tandem Option Plan	25,301		26,283		27,429	

1 *Approximately 29% of options granted in 2010 contain performance vesting conditions.*

The range of exercise prices of tandem and performance tandem options outstanding and exercisable at December 31, 2010 is as follows:

	Outstanding Tandem and Performance Tandem Options			Exercisable Tandem and Performance Tandem Options	
	Number of Options *(thousands)*	Weighted Average Exercise Price *($/option)*	Weighted Average Years to Expiry *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Price *($/option)*
$15.00 to $19.99	3,027	19	3	1,924	19
$20.00 to $24.99	8,613	23	4	1,427	25
$25.00 to $29.99	3,620	28	2	3,428	28
$30.00 to $34.99	3,150	32	1	3,147	32
$35.00 to $39.99	20	36	1	20	36
$40.00 to $44.99	5	40	2	3	40
Total	**18,435**			**9,949**	

(D) STOCK APPRECIATION RIGHTS

In 2010, our board of directors approved amendments to our STARs plans to allow for performance vesting of certain grants. Performance STARs vest over three years if our annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to our industry peer group. The ultimate number of performance STARs that vest will depend upon our performance measured over three calendar years. If our performance is below the specified level compared with our industry peer group, the performance STARs awarded will be forfeited. If our performance is at or above the specified level, the number of performance STARs exercisable shall be determined by our relative ranking. Stock compensation expense related to the performance STARs is accrued based on the price of our common shares at the end of the period and the anticipated performance factor. The expense is recognized over a three-year graded vesting period similar to the existing STARs plan.

Our STARs and performance STARs plans entitle employees to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. Performance STARs are awarded to senior employees. There were no performance STARs exercised during the year ended December 31, 2010. The following stock appreciation and performance stock appreciation rights have been granted:

	2010		2009		2008	
(thousands of shares)	STARs *(thousands*	Weighted Average Exercise Price *($/STAR)*	STARs *(thousands)*	Weighted Average Exercise Price *($/STAR)*	STARs *(thousands)*	Weighted Average Exercise Price *($/STAR)*
Outstanding STARs, Beginning of Year	19,480	25	16,986	25	15,435	24
Granted	3,354[1]	22	5,273	25	4,917	19
Exercised for Cash	(444)	16	(2,079)	13	(2,837)	15
Cancelled	(1,806)	27	(700)	28	(529)	31
Expired	(1,591)	27	–	–	–	–
End of Year	**18,993**	**25**	**19,480**	**25**	**16,986**	**25**
STARs Exercisable at End of Year	10,938	26	9,812	28	8,119	25

1 Approximately 9% of STARs granted in 2010 contain performance vesting conditions.

The range of exercise prices of STARs and performance STARs outstanding and exercisable at December 31, 2010 is as follows:

	Outstanding STARs and Performance STARs			Exercisable STARs and Performance STARs	
	Number of STARs *(thousands)*	Weighted Average Exercise Price *($/STAR)*	Weighted Average Years to Expiry *(years)*	Number of STARs *(thousands)*	Weighted Average Exercise Price *($/STAR)*
$10.00 to $14.99	17	14	3	9	14
$15.00 to $19.99	4,079	18	3	2,661	18
$20.00 to $24.99	8,261	24	4	1,674	25
$25.00 to $29.99	3,606	28	2	3,581	28
$30.00 to $34.99	2,957	32	1	2,952	32
$35.00 to $39.99	71	37	2	60	37
$40.00 to $44.99	2	40	3	1	40
Total	**18,993**			**10,938**	

(E) RESTRICTED SHARE UNITS

In 2010, we adopted our restricted share unit plan (RSUs). RSUs are issued to eligible employees and permit the holder to receive cash payment equal to the market value of the stock on the vesting date. Market price on the vesting date is based on the volume weighted–average closing price during the 20 days prior to the end of the vesting period. RSUs do not have voting rights as there are no shares underlying the plans. A RSU is a notional entry that tracks the value of one Nexen common share. When cash dividends are paid on our common shares, eligible employees are credited RSUs equal to the dividend. All RSUs vest evenly over three years and are exercised and paid as they vest. For employees eligible to retire during the vesting period, the vesting period is accelerated to the retirement date. Obligations are revalued each period based on the market value of our common shares and the number of graded vesting RSUs outstanding.

	Number *(thousands)*	Weighted Average Remaining Time to Expiry *(years)*	Weighted Average Fair Value *($/unit)*
Outstanding at December 31, 2010 and Expected to Vest	925	2	23

There were no RSUs that vested and settled during the year ended December 31, 2010. As at December 31, 2010, we had $18 million of unrecognized compensation expense related to RSUs, which we expect to recognize over a weighted-average period of 1.9 years.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

We assume various contractual obligations and commitments in the normal course of our operations. Our operating leases and transportation, storage and drilling rig commitments as at December 31, 2010 are comprised of the following:

	2011	2012	2013	2014	2015	Thereafter
Operating Leases	98	84	79	56	28	78
Transportation and Storage Commitments	134	108	88	50	25	30
Drilling Rig Commitments	353	395	135	31	–	–

During 2010, total rental expense under operating leases was $62 million (2009—$62 million; 2008—$59 million).

We have a number of lawsuits and claims pending, including income tax reassessments (see Note 17), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

From time to time, we enter into contracts that require us to indemnify parties against certain types of possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary and, generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. We believe that payments, if any, related to existing indemnities would not have a material adverse effect on our liquidity, financial condition or results of operations.

16. MARKETING AND OTHER INCOME

	2010	2009	2008
Marketing Revenue, Net (Note 6)	334	943	467
Long Lake Purchased Bitumen Sales	85	–	–
Change in Fair Value of Crude Oil Put Options (Note 6)	(41)	(251)	203
Interest	7	7	28
Foreign Exchange Gains (Losses)	(14)	128	128
Other	44	32	37
Total	**415**	**859**	**863**

17. INCOME TAXES

(A) TEMPORARY DIFFERENCES

	2010		2009	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Property, Plant and Equipment, Net	32	3,125	36	2,762
Tax Losses Carried Forward	1,632	–	1,092	–
Deferred Income	–	13	–	49
Recoverable Taxes	14	–	20	–
Total	**1,678**	**3,138**	**1,148**	**2,811**

(B) CANADIAN AND FOREIGN PROVISION FOR INCOME TAXES

	2010	2009	2008
Income (Loss) from Continuing Operations before Income Taxes			
Canadian	(847)	(542)	(252)
Foreign	1,973	1,300	3,268
	1,126	758	3,016
Provision for Income Taxes			
Current			
Canadian	–	1	1
Foreign	1,127	772	856
	1,127	773	857
Future			
Canadian	(190)	(166)	(19)
Foreign	(383)	(361)	576
	(573)	(527)	557
Total	**554**	**246**	**1,414**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to the United Kingdom, Yemen, Norway, Colombia and the United States.

(C) RECONCILIATION OF EFFECTIVE TAX RATE TO THE CANADIAN STATUTORY TAX RATE

	2010	2009	2008
Income from Continuing Operations before Provision for Income Taxes	1,126	758	3,016
Provision for Income Taxes Computed at the Canadian Statutory Rate	283	191	845
Add (Deduct) the Tax Effect of:			
Foreign Tax Rate Differential	251	96	530
Higher (Lower) Tax Rates on Capital Gains	1	(42)	9
Federal and Provincial Capital Tax	1	1	2
Effect of Changes in Tax Rates	–	(22)	–
Non-Deductible Expenses and Other	18	22	28
Provision for Income Taxes	**554**	**246**	**1,414**
Effective Tax Rate	**49%**	**32%**	**47%**

(D) AVAILABLE UNUSED TAX LOSSES AND TAX CONTINGENCIES

At December 31, 2010, we had unused tax losses totalling $6,356 million (2009—$4,219 million; 2008—$954 million). The majority of these losses are in Canada and the United States and will expire between 2015 and 2030.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an appropriate provision for income taxes based on available information.

18. DISPOSITIONS

Canadian Heavy Oil

In May 2010, we signed an agreement to sell our heavy oil properties in Canada. The sale closed in July 2010. We received proceeds of $939 million, net of closing adjustments and realized a gain of $781 million in the third quarter. The gain on sale and results of operations of these properties for the last three years have been presented as discontinued operations in Note 20.

Natural Gas Energy Marketing

During the third quarter of 2010, we sold our North American natural gas marketing operations. The sale, which generated proceeds of $9 million, closed in the third quarter and we recognized a non-cash loss on disposition of $259 million. The purchaser acquired our North American natural gas storage and transportation commitments, natural gas inventory, and related financial and physical derivative positions. As is customary with such transactions, not all contracts could be assigned to the purchaser by the closing date. We have a total return swap in place with the purchaser to transfer to them the economic results on the unassigned contracts until they are assigned to the purchaser. The total return swap and unassigned contracts are derivative instruments carried at fair value on our balance sheet. The related gains and losses offset each other for the current and future periods.

In connection with our natural gas energy marketing disposition, we assigned substantially all of our natural gas transportation and storage contracts, reducing our future commitments by $342 million. We agreed to maintain our parental guarantee to the pipeline provider related to one transportation commitment. We are obligated to perform under the guarantee only if the purchaser does not meet its obligation to the pipeline provider. To guarantee its performance, the purchaser provided us with cash collateral of US$43 million for the maximum exposure under the guarantee at that time. This collateral is included in accounts payable. We expect to cancel this guarantee in the first quarter of 2011.

North Dakota/Montana Crude Oil Marketing

During the fourth quarter of 2010, we sold our oil lease gathering, pipelines and storage assets in North Dakota and Montana for proceeds of $201 million. The sale closed in December 2010 and we recognized a gain on disposition of $121 million in the fourth quarter.

Canadian Undeveloped Oil Sands Leases

During the second quarter of 2010, we sold non-core lands in the Athabasca region for proceeds of $81 million. We had no plans to develop these lands for a least a decade. We recognized a gain on disposition of $80 million.

UK Undeveloped Lease

During the fourth quarter of 2010, we sold non-core lands in the UK North Sea for proceeds of $17 million. We had no plans to develop these leases. We recognized a gain on disposition of $17 million in the fourth quarter.

European Gas and Power Marketing

During the first quarter of 2010, we sold our European Gas and Power marketing business for cash proceeds of $15 million. There was no gain or loss on the disposition.

19. SUBSEQUENT EVENTS

In early 2011, we completed the sale of our 62.7% investment in Canexus Limited Partnership, which operates the chemicals business, for net proceeds of $458 million. In the fourth quarter of 2010, we received board approval to sell our interest in Canexus and classified the assets and liabilities as held for sale at December 31, 2010. The results of our chemical business have been presented as discontinued operations for the last three years.

20. DISCONTINUED OPERATIONS

The results of operations of our Canadian heavy oil properties, disposed of during the year and our chemicals business, disposed of in early 2011, are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2010			2009			2008		
	Canada	**Chemicals**	**Total**	**Canada**	**Chemicals**	**Total**	**Canada**	**Chemicals**	**Total**
Revenues and Other Income									
Net Sales	138	456	594	234	458	692	371	477	848
Other	–	25	25	–	50	50	–	(50)	(50)
Gain on Disposition (Note 18)	781	–	781	–	–	–	–	–	–
	919	481	1,400	234	508	742	371	427	798
Expenses									
Operating	50	308	358	97	267	364	114	297	411
Depreciation, Depletion, Amortization and Impairment	35	57	92	122	65	187	71	44	115
Transportation and Other	2	51	53	15	48	63	5	55	60
General and Administrative	10	33	43	21	42	63	14	33	47
Exploration	–	–	–	–	–	–	1	–	1
Interest	–	14	14	–	7	7	–	12	12
	97	463	560	255	429	684	205	441	646
Income (Loss) before Provision for Income Taxes	822	18	840	(21)	79	58	166	(14)	152
Provision for (Recovery of) Income Taxes									
Current	–	5	5	–	3	3	–	2	2
Future	206	(1)	205	(4)	15	11	41	–	41
	206	4	210	(4)	18	14	41	2	43
Income (Loss) before Non-Controlling Interests	616	14	630	(17)	61	44	125	(16)	109
Less: Non-Controlling Interests	–	5	5	–	20	20	–	(4)	(4)
Net Income (Loss) from Discontinued Operations	**616**	**9**	**625**	**(17)**	**41**	**24**	**125**	**(12)**	**113**
Earnings Per Common Share									
Basic			1.19			0.05			0.21
Diluted			1.19			0.05			0.21

Assets and liabilities on the Consolidated Balance Sheet at December 31, 2009, include the following amounts for heavy oil discontinued operations in Canada. There were no assets and liabilities related to heavy oil discontinued operations in Canada at December 31, 2010.

	2010	2009
Property, Plant and Equipment, Net of Accumulated DD&A	–	331
Asset Retirement Obligations	–	(116)
Deferred Credits and Other Liabilities	–	(29)
Total	–	**186**

The following table provides the assets and liabilities that are associated with our chemicals business at December 31, 2010 and 2009.

	2010	2009
Cash and Cash Equivalents	3	14
Accounts Receivable	48	54
Inventories and Supplies	35	33
Other Current Assets	1	3
Property, Plant and Equipment, Net of Accumulated DD&A	643	573
Future Income Tax Asset	7	4
Deferred Charges and Other Assets	11	12
Assets	**748** [1]	**693**
Accounts Payable and Accrued Liabilities	56	67
Accrued Interest Payable	3	–
Long-Term Debt [2]	394	327
Future Income Tax Liability	39	35
Asset Retirement Obligations	41	47
Deferred Credits and Other Liabilities	7	5
Liabilities	**540** [1]	**481**
Equity – Canexus Non-Controlling Interest	**84**	**64**

1 *Included in assets and liabilities held for sale at December 31, 2010.*
2 *Long-term debt included in chemicals liabilities held for sale at December 31, 2010, comprised of:*
- *Term credit facilities of $273 million, available until August 2012, with interest payable monthly at variable rates;*
- *US$50 million notes, repayable in May 2013, with interest payable quarterly at 6.57%;*
- *Convertible debentures of $22 million, maturing December 2014, with interest payable semi-annually at 8% convertible at the holders option subject to certain conditions; and*
- *Convertible debentures of $49 million, maturing December 2015, with interest payable semi-annually at 5.75%, convertible at the holders option subject to certain conditions.*

21. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share using net income divided by the weighted-average number of common shares outstanding. We calculate diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2010	2009	2008
Weighted-Average Number of Common Shares, Basic	524.7	521.4	526.1
Shares Issuable Pursuant to Tandem Options	5.7	10.1	18.8
Shares to be Notionally Purchased from Proceeds of Tandem Options	(4.7)	(7.0)	(12.7)
Weighted-Average Number of Common Shares, Diluted	**525.7**	**524.5**	**532.2**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2010, we excluded 15,432,784 tandem options (2009—13,485,465; 2008—5,694,055) because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding tandem options were the only potential dilutive instruments.

22. CASH FLOWS

(A) CHARGES AND CREDITS TO INCOME NOT INVOLVING CASH

	2010	2009	2008
Depreciation, Depletion, Amortization and Impairment	1,662	1,615	1,899
Stock-Based Compensation	(41)	(10)	(272)
Net Loss (Gains) on Dispositions	41	–	–
Non-cash items included in Discontinued Operations	(499)	149	210
Provision for (Recovery of) Future Income Taxes	(573)	(527)	557
Change in Fair Value of Crude Oil Put Options	41	251	(203)
Foreign Exchange	14	(128)	(58)
Other	(5)	21	7
Total	**640**	**1,371**	2,140

(B) CHANGES IN NON-CASH WORKING CAPITAL

	2010	2009	2008
Accounts Receivable	96	92	950
Inventories and Supplies	(105)	(236)	246
Other Current Assets	47	9	5
Accounts Payable and Accrued Liabilities	241	(23)	(1,232)
Other Current Liabilities	–	23	26
Total	**279**	**(135)**	(5)
Relating to:			
Operating Activities	338	(25)	119
Investing Activities	(59)	(110)	(124)
Total	**279**	**(135)**	(5)

(C) OTHER CASH FLOW INFORMATION

	2010	2009	2008
Interest Paid	380	335	319
Income Taxes Paid	951	483	1,055

Cash flow from other operating activities includes cash outflows related to geological and geophysical expenditures of $100 million (2009—$81 million; 2008—$137 million).

23. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and G[illegible] We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in Colombia, offshore West Africa and Norway. We also own 7.23% of Syncrude, which develops and produces synthetic crude oil from mining bitumen in the Athabasca oil sands in northern Alberta.

Energy Marketing: Our energy marketing group sells our crude oil and natural gas proprietary production and markets third-party crude oil, natural gas and power (including electricity generation). We use financial and derivative contracts, including futures, forwards, swaps and options for economic hedging and trading purposes. Our energy marketing group also uses physical commodity transportation and storage capacity contracts to capture regional crude oil opportunities. We sold a portion of our energy marketing business in 2010 (see Note 18).

[illegible] Canexus manufactures, markets and distributes industrial chemicals, principally sodium chlorate, chlorine, muriatic acid and caustic soda. They produce sodium chlorate at three facilities in Canada and one in Brazil. They produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil. In early 2011, we disposed of our investment in Canexus as described in Note 19. As at December 31, 2010, these operations have been presented as held for sale and results of operations for the last three years have been included in discontinued operations (see Note 20). Our chemicals financial position and results of operations is included with Corporate, Chemicals and Other.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

2010 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: United Kingdom	Oil and Gas: Canada[1]	Oil and Gas: Syncrude	Oil and Gas: United States	Oil and Gas: Yemen	Oil and Gas: Other Countries[2]	Energy Marketing	Corporate, Chemicals and Other	Total
Net Sales[3]	3,115	503	580	424	696	54	39	–	5,411
Marketing and Other	17	87	5	1	16	–	334	(45)[4]	415
	3,132	590	585	425	712	54	373	(45)	5,826
Less: Expenses									
Operating	335	442	284	97	158	5	33	–	1,354
Depreciation, Depletion, Amortization and Impairment[5]	827	259	53	343	112	9	18	41	1,662
Transportation and Other	2	201	21	2	26	1	314	(1)	566
General and Administrative[6]	22	45	1	62	6	27	69	207	439
Exploration	67	42	–	115	–	104[7]	–	–	328
Interest	–	–	–	–	–	–	–	310	310
Net (Gains) Loss on Disposition	(17)	(80)	–	–	–	–	138	–	41
Income (Loss) from Continuing Operations before Income Taxes	1,896	(319)	226	(194)	410	(92)	(199)	(602)	1,126
Less: Provision for (Recovery of) Income Taxes[8]	834	(80)	57	(67)	143	(83)	(78)	(172)	554
Income (Loss) from Continuing Operations	1,062	(239)	169	(127)	267	(9)	(121)	(430)	572
Add: Net Income from Discontinued Operations[9]	–	590	–	–	–	–	26	9	625
Net Income (Loss)	**1,062**	**351**	**169**	**(127)**	**267**	**(9)**	**(95)**	**(421)**	**1,197**
Identifiable Assets	**4,251**	**8,002**[10]	**1,339**	**1,662**	**248**	**1,412**[11]	**1,778**[12]	**3,215**[13]	**21,907**
Capital Expenditures									
Exploration and Development	596	773	100	214	52	578	29	181	2,523
Proved Property Acquisitions	79	–	–	–	–	–	–	–	79
Total	**675**	**773**	**100**	**214**	**52**	**578**	**29**	**181**	**2,602**
PP&E									
Cost	6,610	8,729	1,545	3,913	2,379	1,362	195	397	25,130
Less: Accumulated DD&A	3,273	883	305	2,689	2,312	88	66	265	9,881
Net Book Value[3]	**3,337**	**7,846**[10]	**1,240**	**1,224**	**67**	**1,274**[11]	**129**	**132**	**15,249**
Goodwill[14]	**277**	–	–	–	–	–	**9**	–	**286**

1 Includes results of operations from conventional, oil sands, shale gas and CBM.
2 Includes results of operations from producing activities in Colombia.
3 Net sales made from all segments originating in Canada: $1,122 million
PP&E located in Canada: $9,347 million
4 Includes interest income of $7 million, foreign exchange losses of $14 million, decrease in the fair value of crude oil put options of $41 million and other gains of $3 million.
5 Includes an impairment charge related to gas properties in the US Gulf of Mexico of $93 million.
6 Includes net recovery of stock-based compensation expense of $14 million.
7 Includes exploration activities primarily in Norway, Nigeria and Colombia.
8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
9 Discontinued operations are disclosed in Note 20.
10 Includes $6,179 million related to our insitu oil sands (Long Lake and future phases)
11 Includes $1,222 million related to our Usan development, offshore Nigeria.
12 84% of marketing's identifiable assets are accounts receivable and inventories.
13 Includes $748 million of assets held for sale relating to our chemicals operations (see Note 20).
14 Goodwill decreased in the UK by $15 million as a result of changes in foreign exchange rates. Goodwill decreased in energy marketing by $38 million as a result of our various dispositions and changes in foreign exchange rates.

2009 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: United Kingdom	Canada	Syncrude	United States	Yemen	Other Countries[1]	Energy Marketing	Corporate, Chemicals and Other	Total
Net Sales[2]	2,430	161	480	321	705	70	36	–	4,203
Marketing and Other	18	1	7	–	14	6	943	(130)[3]	859
	2,448	162	487	321	719	76	979	(130)	5,062
Less: Expenses									
Operating	253	74	265	98	191	8	27	–	916
Depreciation, Depletion, Amortization and Impairment[4]	875	179	63	312	102	14	27	43	1,615
Transportation and Other	17	12	28	22	30	–	599	24	732
General and Administrative[5]	18	46	1	60	6	35	91	177	434
Exploration	50	84	–	104	–	64[6]	–	–	302
Interest	–	–	–	–	–	–	–	305	305
Income (Loss) from Continuing Operations before Income Taxes	1,235	(233)	130	(275)	390	(45)	235	(679)	758
Less: Provision for (Recovery of) Income Taxes[7]	487	(60)	33	(95)	141	(23)	96	(333)	246
Add: Net Income (Loss) from Discontinued Operations[8]	–	(17)	–	–	–	–	–	41	24
Net Income (Loss)	**748**	**(190)**	**97**	**(180)**	**249**	**(22)**	**139**	**(305)**	**536**
Identifiable Assets	**4,866**	**7,809[9]**	**1,287**	**1,715**	**229**	**1,090**	**3,050[10]**	**2,854**	**22,900**
Capital Expenditures									
Exploration and Development	626	843	87	285	69	557	28	247	2,742
Proved Property Acquisitions	–	755	–	–	–	–	–	–	755
Total	**626**	**1,598**	**87**	**285**	**69**	**557**	**28**	**247**	**3,497**
PP&E									
Cost	6,115	9,664	1,463	3,900	2,462	930	259	1,506	26,299
Less: Accumulated DD&A	2,664	2,038	270	2,529	2,322	99	83	802	10,807
Net Book Value[2]	**3,451**	**7,626[9]**	**1,193**	**1,371**	**140**	**831**	**176**	**704**	**15,492**
Goodwill[11]	**292**	–	–	–	–	–	**47**	–	**339**

1 *Includes results of operations from producing activities in Colombia.*
2 *Net sales made from all segments originating in Canada: $1,063 million*
PP&E located in Canada: $9,610 million
3 *Includes interest income of $7 million, foreign exchange gains of $128 million, decrease in the fair value of crude oil put options of $251 million and other losses of $14 million.*
4 *Includes an impairment charge related to gas properties in Canada and the US Gulf of Mexico of $58 million and $20 million, respectively.*
5 *Includes stock-based compensation expense of $69 million.*
6 *Includes exploration activities primarily in Norway, Nigeria and Colombia.*
7 *The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.*
8 *Discontinued operations are disclosed in Note 20.*
9 *Includes $6,045 million related to our insitu oil sands (Long Lake and future phases).*
10 *78% of marketing's identifiable assets are accounts receivable and inventories.*
11 *Goodwill decreased in the UK and energy marketing by $49 million and $2 million, respectively, as a result of changes in foreign exchange rates.*

2008 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: United Kingdom	Canada	Syncrude	United States	Yemen	Other Countries[1]	Energy Marketing	Corporate, Chemicals and Other	Total
Net Sales[2]	3,580	285	691	665	1,093	192	70	–	6,576
Marketing and Other	5	3	6	4	12	–	467	366[3]	863
	3,585	288	697	669	1,105	192	537	366	7,439
Less: Expenses									
Operating	253	68	280	94	176	10	43	–	924
Depreciation, Depletion, Amortization and Impairment[4]	999	137	49	475	160	17	19	43	1,899
Transportation and Other	19	7	16	3	9	–	805	48	907
General and Administrative[5]	(8)	6	1	38	(7)	13	79	88	210
Exploration	86	78	–	109	5	123[6]	–	–	401
Interest	–	–	–	–	–	–	–	82	82
Income (Loss) from Continuing Operations before Income Taxes	2,236	(8)	351	(50)	762	29	(409)	105	3,016
Less: Provision for (Recovery of) Income Taxes[7]	1,126	4	99	(19)	264	(4)	(102)	46	1,414
Add: Net Income (Loss) from Discontinued Operations[8]	–	125	–	–	–	–	–	(12)	113
Net Income (Loss)	**1,110**	**113**	**252**	**(31)**	**498**	**33**	**(307)**	**47**	**1,715**
Identifiable Assets	**6,632**	**6,643[9]**	**1,198**	**2,044**	**342**	**701**	**3,280[10]**	**1,315**	**22,155**
Capital Expenditures									
Exploration and Development	691	1,405	55	405	101	238	8	141	3,044
Proved Property Acquisitions	–	22	–	–	–	–	–	–	22
Total	**691**	**1,427**	**55**	**405**	**101**	**238**	**8**	**141**	**3,066**
PP&E									
Cost	6,532	8,134	1,372	4,398	2,808	554	246	1,271	25,315
Less: Accumulated DD&A	2,159	1,786	236	2,702	2,610	113	76	711	10,393
Net Book Value[2]	**4,373**	**6,348[9]**	**1,136**	**1,696**	**198**	**441**	**170**	**560**	**14,922**
Goodwill	**341**	**–**	**–**	**–**	**–**	**–**	**49**	**–**	**390**

1 Includes results of operations from producing activities in Colombia.
2 Net sales made from all segments originating in Canada: $1,570 million
PP&E located in Canada: $8,121 million
3 Includes interest income of $28 million, foreign exchange gains of $128 million, increase in the fair value of crude oil put options of $203 million and other income of $7 million.
4 Includes an impairment charge related to oil and gas properties in the UK North Sea and the US Gulf of Mexico of $318 million and $250 million, respectively.
5 Includes recovery of stock-based compensation expense of $160 million.
6 Includes exploration activities primarily in Norway, Nigeria and Colombia.
7 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
8 Discontinued operations are disclosed in Note 20.
9 Includes $4,742 million related to our insitu oil sands (Long Lake and future phases).
10 79% of marketing's identifiable assets are accounts receivable and inventories.

24. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP for the Three Years Ended December 31, 2010

(Cdn$ millions, except per-share amounts)	2010	2009	2008
Revenues and Other Income			
Net Sales	5,411	4,203	6,576
Marketing and Other (v)	449	847	846
	5,860	5,050	7,422
Expenses			
Operating	1,354	916	924
Depreciation, Depletion, Amortization and Impairment	1,662	1,615	1,899
Transportation and Other	566	732	904
General and Administrative (iv)	435	469	216
Exploration	328	302	401
Interest	310	305	82
Net Loss from Dispositions	41	–	–
	4,696	4,339	4,426
Income from Continuing Operations before Provision for Income Taxes	1,164	711	2,996
Provision for (Recovery of) Income Taxes			
Current	1,127	773	857
Deferred (iv); (v)	(550)	(545)	548
	577	228	1,405
Net Income from Continuing Operations	587	483	1,591
Net Income from Discontinued Operations	625	24	113
Net Income - US GAAP [1]	**1,212**	**507**	**1,704**
Earnings Per Common Share from Continuing Operations *($/share)* (Note 21)			
Basic	1.12	0.92	3.03
Diluted	1.11	0.92	2.99
Earnings Per Common Share *($/share)* (Note 21)			
Basic	2.31	0.97	3.24
Diluted	2.30	0.97	3.20

1 *Reconciliation of Canadian and US GAAP Net Income*

(Cdn$ millions)	***2010***	***2009***	***2008***
Net Income — Canadian GAAP	*1,197*	*536*	*1,715*
Impact of US Principles, Net of Income Taxes:			
Stock-based Compensation (iv)	*(8)*	*(26)*	*(4)*
Inventory Valuation (v)	*23*	*(10)*	*(7)*
Deferred Taxes (vi)	*–*	*7*	*–*
Net Income — US GAAP	***1,212***	***507***	***1,704***

Consolidated Balance Sheet—US GAAP December 31, 2010 and 2009

(Cdn$ millions, except share amounts)	2010	2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	1,005	1,700
Restricted Cash	40	198
Accounts Receivable	1,938	2,788
Inventories and Supplies (v)	513	610
Other	142	185
Assets Held for Sale	748	–
Total Current Assets	4,386	5,481
Property, Plant and Equipment Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $10,274 (December 31, 2009—$11,200) (i); (iii)	15,200	15,443
Goodwill	286	339
Deferred Income Tax Assets	1,678	1,148
Deferred Charges and Other Assets	272	370
TOTAL ASSETS	**21,822**	**22,781**
LIABILITIES		
Current Liabilities		
Accounts Payable and Accrued Liabilities (iv)	2,634	3,131
Accrued Interest Payable	83	89
Dividends Payable	26	26
Liabilities Held for Sale	540	–
Total Current Liabilities	3,283	3,246
Long-Term Debt	5,079	7,251
Deferred Income Tax Liabilities (i); (ii); (iv); (v); (vi)	3,054	2,720
Asset Retirement Obligations	1,009	1,018
Deferred Credits and Other Liabilities (ii)	852	1,126
Equity		
Nexen Inc. Shareholders' Equity		
Common Shares, no par value Authorized: Unlimited Outstanding: 2010—525,706,403 shares 2009—522,915,843 shares	1,111	1,049
Contributed Surplus	–	1
Retained Earnings (i); (iii); (iv); (v); (vi)	7,683	6,575
Accumulated Other Comprehensive Loss (ii)	(333)	(269)
Total Nexen Inc. Shareholders' Equity	8,461	7,356
Canexus Non-Controlling Interest	84	64
Total Equity	8,545	7,420
Commitments, Contingencies and Guarantees		
TOTAL LIABILITIES AND EQUITY	**21,822**	**22,781**

Consolidated Statement of Comprehensive Income—US GAAP
For the Three Years ended December 31, 2010

(Cdn$ millions)	2010	2009	2008
Net Income—US GAAP	1,212	507	1,704
Other Comprehensive Income (Loss), Net of Income Taxes:			
Foreign Currency Translation Adjustment	(29)	(56)	159
Change in Mark to Market on Cash Flow Hedges	–	–	–
Unamortized Defined Benefit Pension Plan Costs (ii)	(35)	(4)	(21)
Comprehensive Income — US GAAP	**1,148**	**447**	**1,842**

Consolidated Statement of Accumulated Other Comprehensive Loss—US GAAP
December 31, 2010 and 2009

(Cdn$ millions)	2010	2009
Foreign Currency Translation Adjustment	(219)	(190)
Unamortized Defined Benefit Pension Plan Costs (ii)	(114)	(79)
Accumulated Other Comprehensive Loss (AOCL)	**(333)**	**(269)**

Notes to the Consolidated US GAAP Financial Statements

We have not included a US GAAP Consolidated Statement of Cash Flows as we have not identified any cash flow differences between Canadian and US GAAP.

i. Under Canadian GAAP, we defer certain development costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:
   - PP&E is lower under US GAAP by $30 million and deferred income tax liabilities are $11 million lower.

ii. US GAAP requires the recognition of the over-funded and under-funded status of defined benefit pension plans on the balance sheet as an asset or liability. At year end, the unfunded amount of our defined benefit pension plans that was not included in the pension liability under Canadian GAAP was $156 million (2009—$105 million). This amount has been included in deferred credits and other liabilities, and $114 million, net of income taxes (2009—$79 million, net of income taxes) has been included in accumulated other comprehensive income. Deferred income tax liabilities are $42 million lower (2009—lower by $26 million).

iii. On January 1, 2003, we adopted *Accounting for Asset Retirement Obligations* for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

iv. Under Canadian principles, we record obligations for liability-based stock compensation plans using the intrinsic-value method of accounting. Under US principles, obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting. As a result:
   - general and administrative expense is lower by $4 million (higher by $8 million, net of income taxes) for the year ended December 31, 2010 (2009—higher by $35 million ($26 million, net of income taxes); 2008—higher by $6 million ($4 million, net of income taxes)); and
   - accounts payable and accrued liabilities are higher by $89 million at December 31, 2010 (2009—higher by $93 million) and deferred income tax liabilities are $14 million lower (2009—lower by $26 million).

v. Under Canadian GAAP, we carry our commodity inventory held for trading purposes at fair value, less any costs to sell. Under US GAAP, we are required to carry this inventory at the lower of cost or net realizable value. As a result marketing and other income is higher by $34 million ($23 million, net of income taxes) for the year ended December 31, 2010 (2009—lower by $12 million, ($10 million, net of income taxes); 2008—lower by $14 million ($7 million, net of income

taxes)); and inventories are lower by $36 million at December 31, 2010 (2009—lower by $70 million) and deferred income tax liabilities are $12 million lower (2009—lower by $23 million).

vi. Under US GAAP, we are required to apply Accounting Standards Codification (ASC) Topic 740 *Accounting for Uncertainty in Income Taxes* regarding accounting and disclosure for uncertain tax positions. As at December 31, 2010, the total amount of our unrecognized tax benefits was approximately $291 million, all of which, if recognized, would affect our effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the Consolidated Statement of Income. As at December 31, 2010, the total amount of interest and penalties related to uncertain tax positions recognized in deferred income tax liabilities in the US GAAP—Consolidated Balance Sheet was approximately $10 million. We had no interest or penalties included in the US GAAP—Consolidated Statement of Income for the year ended December 31, 2010.

Our income tax filings are subject to audit by taxation authorities and as at December 31, 2010, the following tax years remained subject to examination: (i) Canada—1985 to date; (ii) United Kingdom—2008 to date; and (iii) United States—2005 to date. We do not anticipate any material changes to the unrecognized tax benefits previously disclosed within the next 12 months.

Reconciliation of Unrecognized Tax Benefits

(Cdn$ millions)	
Balance at January 1, 2010	277
Additions for tax positions related to the current year	19
Additions for tax positions related to prior years	26
Reductions for tax positions related to prior years	(31)
Balance at December 31, 2010	291

US GAAP STOCK-BASED COMPENSATION

Under US GAAP, our stock-based compensation expense is accounted for by applying ASC Topic 718 *Compensation-Stock Compensation*. Under this guidance, our tandem options, performance tandem options, stock appreciation rights, performance stock appreciation rights, and restricted share units are considered liability-based stock compensation plans. Obligations for liability-based stock compensation plans are measured at the estimated fair value and remeasured in each subsequent reporting period.

Assumptions

We use the Generalized Black-Scholes option pricing model to estimate the fair value of TOPs and STARs. The following assumptions are made:

Expected Annual Dividends per Common Share *($/share)*	0.20
Expected Volatility	56%
Risk-Free Interest Rate	1.6%–2.6%
Weighted-Average Expected Life of Compensation Instruments *(years)*	3.1–3.3

These assumptions are based on multiple factors, including historical exercise patterns of employees in relatively homogenous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for those same homogenous groups, the historical volatility of our stock price, our expected future dividend levels and the interest rate for Government of Canada bonds.

We use the Monte Carlo option pricing model to simulate expected returns and estimate the fair value of our Performance TOPs and Performance STARs. The model simulates our expected total shareholder return relative to our industry peer group. This is applied to the reward criteria of the performance TOPs and STARs to give an expected value at the measurement date. The assumptions used in the Monte Carlo option pricing model are similar to those used in the Generalized Black-Scholes option pricing model, only the Monte Carlo option pricing model assumes a risk-free interest rate of 1.87%.

Tandem Options

	Number (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/option)
Outstanding at December 31, 2010	18,435	25	3.1	15	5.42
Outstanding at December 31, 2010 and Expected to Vest	17,907	25	3.0	14	5.33
Exercisable at December 31, 2010	9,949	27	2.0	7	3.14

The total intrinsic value of tandem options exercised during the year ended December 31, 2010 was $31 million (2009—$66 million; 2008—$88 million). There were no performance tandem options exercised during the year ended December 31, 2010. As at December 31, 2010, we had $47 million (2009 —$55 million) of unrecognized compensation expense related to tandem options, which we expect to recognize over a weighted-average period of 1.6 years (2009 —1.6 years).

Stock Appreciation Rights

	Number (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/right)
Outstanding at December 31, 2010	18,993	25	3.0	20	5.29
Outstanding at December 31, 2010 and Expected to Vest	18,392	25	3.0	19	5.20
Exercisable at December 31, 2010	10,938	26	2.1	12	3.38

The total intrinsic value of stock appreciation rights exercised during the year ended December 31, 2010 was $3 million (2009—$26 million; 2008—$52 million). There were no performance stock appreciation rights exercised during the year ended December 31, 2010. As at December 31, 2010, we had $40 million (2009 —$64 million) of unrecognized compensation expense related to stock appreciation rights, which we expect to recognize over a weighted-average period of 1.5 years (2009 —1.6 years).

Restricted Share Units

	Number (thousands)	Weighted Average Remaining Term to Expiry (years)	Aggregate Intrinsic Value (Cdn$ millions)	Weighted Average Fair Value ($/right)
Outstanding at December 31, 2010	925	2.0	21	22.80
Outstanding at December 31, 2010 and Expected to Vest	839	2.0	19	22.80
Exercisable at December 31, 2010	–	–	–	–

RSUs settle on each vesting date. There were no RSUs that vested and settled during the year ended December 31, 2010. As at December 31, 2010, we had $18 million of unrecognized compensation expense related to RSUs, which we expect to recognize over a weighted-average period of 1.9 years.

Stock-Based Compensation Expense and Payments

For the year ended December 31, 2010, stock-based compensation recovery of $18 million (2009—$104 million recovery; 2008—$154 million recovery) was included in general and administrative expense in the Consolidated Statement of Income—US GAAP.

For the year ended December 31, 2010, cash proceeds of $5 million were received related to the exercise of stock options (2009—$12 million; 2008—$23 million). For the year ended December 31, 2010, $29 million was paid related to the exercise of stock options and stock appreciation rights (2009—$81 million; 2008—$121 million). The income tax benefit recorded from the exercise of stock options and stock appreciation rights was $1 million (2009—$20 million; 2008—$34 million) for the period.

New Accounting Pronouncement—US GAAP

In January 2010, FASB issued guidance to improve financial instrument fair value measurement disclosures. The guidance requires entities to describe transfers between the three levels of the fair value hierarchy and present items separately in the Level 3 reconciliation. This guidance is consistent with fair value measurement disclosures adopted for Canadian GAAP in 2009. Adoption of this guidance did not have an impact on our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Oil and Gas Producing Activities (Unaudited)

The following oil and gas information is provided in accordance with the Financial Accounting Standards Board (FASB) Topic 932 *Extractive Activities—Oil and Gas*.

(A) RESERVE QUANTITY INFORMATION

Our net proved reserves and changes in those reserves for our oil and gas operations are disclosed on pages 174 to 175.

The net proved reserves represent management's estimate of remaining proved oil and gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the proved reserves have been assessed by independent qualified reserves consultants.

Estimates of proved oil and gas reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under existing economic and operating conditions based on the 12-month average prices for 2009 and 2010, and year-end prices for prior years. See Basis of Reserves Estimates on pages 31 to 34 for a description of our oil and gas reserves estimation process.

	Total—by Product					Canada				
						Oil Sands				
	Total *(mmboe)*	Synthetic Oil *(mmbbl)*	Bitumen *(mmbbl)*	Oil *(mmbbl)*	Gas *(bcf)*	Syncrude Synthetic Oil[1] *(mmbbl)*	Insitu Synthetic Oil[2] *(mmbbl)*	Insitu Bitumen[2] *(mmbbl)*	Oil *(mmbbl)*	Gas *(bcf)*
Proved Reserves after Royalties										
December 31, 2007	**917**	**267**	**234**	**327**	**532**	**267**	–	**234**	**47**	**318**
Extensions & Discoveries	40	7	19	7	39	7	–	19	1	34
Revisions—Technical	27	–	–	20	40	–	–	–	(3)	54
Revisions—Economic[3]	21	28	31	(34)	(21)	28	–	31	(19)	(16)
Acquisitions	–	–	–	–	–	–	–	–	–	–
Divestments	–	–	–	–	–	–	–	–	–	–
Production	(79)	(7)	(2)	(58)	(71)	(7)	–	(2)	(4)	(40)
December 31, 2008	**926**	**295**	**282**	**262**	**519**	**295**	**–**	**282**	**22**	**350**
Extensions & Discoveries	63	7	23	28	33	7	–	23	1	16
Revisions—Technical	9	–	(4)	10	16	–	–	(4)	(1)	12
Revisions—Economic[3]	(2)	(7)	(9)	27	(81)	(7)	–	(9)	13	(87)
Acquisitions	85	–	85	–	–	–	–	85	–	–
Divestments	–	–	–	–	–	–	–	–	–	–
Production	(78)	(7)	(3)	(55)	(76)	(7)	–	(3)	(4)	(47)
	1,003	288	374	272	411	288	–	374	31	244
SEC Rule Transition [2]	(83)	291	(374)	–	–	–	291	(374)	–	–
December 31, 2009	**920**	**579**	**–**	**272**	**411**	**288**	**291**	**–**	**31**	**244**
Extensions & Discoveries	66	10	–	36	121	7	3	–	–	90
Revisions—Technical	27	(3)	–	27	21	–	(3)	–	–	(16)
Revisions—Economic[3]	13	12	–	1	1	8	4	–	–	7
Acquisitions	1	–	–	1	3	–	–	–	–	–
Divestments	(30)	–	–	(29)	(8)	–	–	–	(29)	(8)
Production	(79)	(11)	–	(53)	(90)	(7)	(4)	–	(2)	(42)
December 31, 2010	**918**	**587**	**–**	**255**	**459**	**296**	**291**	**–**	**–**	**275**
Proved Undeveloped										
December 31, 2009	413	339	–	69	32	103	236	–	2	3
December 31, 2010	**472**	**358**	**–**	**94**	**122**	**114**	**244**	**–**	**–**	**44**
Proved Developed[6]										
December 31, 2009	507	240	–	203	379	185	55	–	29	241
December 31, 2010	**446**	**229**	**–**	**161**	**337**	**182**	**47**	**–**	**–**	**231**

(Continued on following page)

	United Kingdom		United States		Other Countries[4,5]
	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)
Proved Reserves after Royalties					
December 31, 2007	**203**	**25**	**21**	**189**	**56**
Extensions & Discoveries	5	–	–	5	1
Revisions—Technical	17	–	2	(14)	4
Revisions—Economic[3]	(16)	–	(3)	(5)	4
Acquisitions	–	–	–	–	–
Divestments	–	–	–	–	–
Production	(37)	(7)	(3)	(24)	(14)
December 31, 2008	**172**	**18**	**17**	**151**	**51**
Extensions & Discoveries	19	6	1	11	7
Revisions—Technical	5	2	1	2	5
Revisions—Economic[3]	9	–	3	6	2
Acquisitions	–	–	–	–	–
Divestments	–	–	–	–	–
Production	(36)	(9)	(3)	(20)	(12)
	169	17	19	150	53
SEC Rule Transition [2]	–	–	–	–	–
December 31, 2009	**169**	**17**	**19**	**150**	**53**
Extensions & Discoveries	35	29	–	2	1
Revisions—Technical	25	32	1	5	1
Revisions—Economic[3]	1	–	–	(6)	–
Acquisitions	1	3	–	–	–
Divestments	–	–	–	–	–
Production	(38)	(14)	(3)	(34)	(10)
December 31, 2010	**193**	**67**	**17**	**117**	**45**
Proved Undeveloped					
December 31, 2009	27	4	6	25	34
December 31, 2010	**55**	**55**	**5**	**23**	**34**
Proved Developed[6]					
December 31, 2009	142	13	13	125	19
December 31, 2010	**138**	**12**	**12**	**94**	**11**

1 *As of December 31, 2009, our Syncrude oil sands activities were considered an oil and gas activity rather than a mining activity.*

2 *As of December 31, 2009, our insitu oil sands reserves are presented as synthetic oil barrels rather than bitumen barrels.*

3 *Prices underlying our economic assumptions used for reserve estimation in 2009 and 2010 are based on the average first-day-of-the-month prices during the year rather than the year-end prices used in 2008.*

4 *Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.*

5 *Represents reserves in Yemen, Nigeria and Colombia.*

6 *Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.*

(B) CAPITALIZED COSTS

Syncrude activities and field-upgrading operations for our insitu oil sands production are considered oil and gas activities effective December 31, 2009. Information for Syncrude and insitu upgrading for 2010 and 2009 has been provided. As the change in the rules was applied prospectively, information for 2008 has not been restated.

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
December 31, 2010				
United Kingdom	5,633	977	(3,273)	3,337
Canada	2,209	589	(1,180)	1,618
Oil Sands Insitu[1]	5,387	888	(96)	6,179
Oil Sands Syncrude	1,545	–	(305)	1,240
United States	3,655	258	(2,689)	1,224
Other Countries	3,688	53	(2,400)	1,341
Total Capitalized Costs	**22,117**	**2,765**	**(9,943)**	**14,939**
December 31, 2009				
United Kingdom	4,995	1,120	(2,664)	3,451
Canada	3,383	573	(2,424)	1,532
Oil Sands Insitu[1]	5,223	829	(7)	6,045
Oil Sands Syncrude	1,463	–	(270)	1,193
United States	3,665	235	(2,529)	1,371
Other Countries	3,340	52	(2,421)	971
Total Capitalized Costs	**22,069**	**2,809**	**(10,315)**	**14,563**
December 31, 2008				
United Kingdom	5,954	578	(2,159)	4,373
Canada	3,166	566	(2,175)	1,557
Oil Sands Insitu[1]	1,921	501	(4)	2,418
United States	4,152	246	(2,702)	1,696
Other Countries	3,317	45	(2,723)	639
Total Capitalized Costs	**18,510**	**1,936**	**(9,763)**	**10,683**

1 *Capitalized costs in 2008 reflect bitumen production activities only; 2009 and 2010 amounts reflect upgrading activities to produce synthetic barrels.*

(C) COSTS INCURRED

Syncrude activities and field-upgrading operations for our insitu oil sands production are considered oil and gas activities effective December 31, 2009. Information for 2010 and 2009 for Syncrude and insitu upgrading has been provided. As the change in the rules was applied prospectively, information for 2008 has not been restated.

(Cdn$ millions)	Total Oil and Gas	United Kingdom	Canada Other	Oil Sands Insitu[1]	Oil Sands Syncrude	United States	Other Countries
Year Ended December 31, 2010							
Property Acquisition Costs							
Proved	79	79	–	–	–	–	–
Unproved	552	176	315	–	–	61	–
Exploration Costs	505	60	223	1	–	117	104
Development Costs	1,565	505	56	224	95	130	555
Total Costs Incurred[2]	**2,701**	**820**	**594**	**225**	**95**	**308**	**659**
Year Ended December 31, 2009							
Property Acquisition Costs							
Proved	755	–	–	755	–	–	–
Unproved	13	–	3	–	–	10	–
Exploration Costs	650	155	224	1	–	183	87
Development Costs	1,923	457	115	549	114	120	568
Total Costs Incurred	**3,341**	**612**	**342**	**1,305**	**114**	**313**	**655**
Year Ended December 31, 2008							
Property Acquisition Costs							
Proved	22	–	2	20	–	–	–
Unproved	69	–	6	–	–	63	–
Exploration Costs	650	157	220	2	–	132	139
Development Costs	1,983	555	205	537	–	404	282
Total Costs Incurred	**2,724**	**712**	**433**	**559**	**–**	**599**	**421**

1 *Costs incurred in 2008 reflect bitumen production activities only; 2009 and 2010 amounts reflect upgrading activities to produce synthetic barrels*

2 *Total costs incurred includes asset retirement costs of $209 million and geological and geophysical costs of $100 million and excludes costs related to chemicals, energy marketing, corporate and other of $210 million.*

(D) RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

Syncrude activities and field-upgrading operations for our insitu oil sands production are considered oil and gas activities effective December 31, 2009. Information for 2010 and 2009 for Syncrude and insitu upgrading has been provided. As the change in the rules was applied prospectively, information for 2008 has not been restated.

(Cdn$ millions)	Total Oil and Gas	United Kingdom	Canada [1]	Oil Sands Syncrude	United States	Other Countries
Year Ended December 31, 2010						
Net Sales	5,510	3,115	641	580	424	750
Production Costs	1,371	335	492	284	97	163
Exploration Expense	328	67	42	–	115	104
Depreciation, Depletion, Amortization and Impairment	1,638	827	294	53	343	121
Other Expenses (Income)	(541)	(10)	(655)	17	63	44
	2,714	1,896	468	226	(194)	318
Income Tax Provision (Recovery)	1,001	834	117	57	(67)	60
Results of Operations	**1,713**	**1,062**	**351**	**169**	**(127)**	**258**
Year Ended December 31, 2009						
Net Sales	4,401	2,430	395	480	321	775
Production Costs	986	253	171	265	98	199
Exploration Expense	302	50	84	–	104	64
Depreciation, Depletion, Amortization and Impairment	1,667	875	301	63	312	116
Other Expenses	265	17	93	22	82	51
	1,181	1,235	(254)	130	(275)	345
Income Tax Provision (Recovery)	479	487	(64)	33	(95)	118
Results of Operations	**702**	**748**	**(190)**	**97**	**(180)**	**227**
Year Ended December 31, 2008						
Net Sales	6,186	3,580	656	–	665	1,285
Production Costs	715	253	182	–	94	186
Exploration Expense	402	86	79	–	109	128
Depreciation, Depletion, Amortization and Impairment	1,859	999	208	–	475	177
Other Expenses (Income)	75	6	29	–	37	3
	3,135	2,236	158	–	(50)	791
Income Tax Provision (Recovery)	1,412	1,126	45	–	(19)	260
Results of Operations	**1,723**	**1,110**	**113**	**–**	**(31)**	**531**

1 Includes the results of discontinued operations.

(E) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying average annual prices to our after royalty share of estimated annual future production from proved oil and gas reserves. As a result of amended FASB oil and gas disclosure rules, future cash inflows as of December 31, 2009 and thereafter were computed using the average first-day-of-the-month prices for the year held constant. Future cash inflows at December 31, 2008 were computed using the year-end prices held constant. Future development, production and abandonment costs to be incurred in producing and further developing the proved reserves are based on existing cost indicators. Future income taxes are computed by applying year-end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the prices used.

As a result of changes to oil and gas disclosure rules issued by FASB, Syncrude and field upgrading operations are considered oil and gas activities from 2009 onward.

		Canada					
(Cdn$ millions)	Total	Oil Sands Syncrude	Oil Sands Insitu[1]	Other	United Kingdom	United States	Other Countries
December 31, 2010							
Future Cash Inflows	69,323	23,998	23,293	1,049	15,594	1,831	3,558
Future Production Costs	33,631	14,002	13,200	706	4,437	449	837
Future Development Costs	6,875	1,061	3,142	95	1,608	253	716
Future Dismantlement and Site Restoration Costs, Net	2,226	182	147	242	1,094	432	129
Future Income Tax	6,251	1,241	416	–	4,433	–	161
Future Net Cash Flows	20,340	7,512	6,388	6	4,022	697	1,715
10% Discount Factor	11,875	5,579	4,665	(65)	985	126	585
Standardized Measure	**8,465**	**1,933**	**1,723**	**71**	**3,037**	**571**	**1,130**
December 31, 2009							
Future Cash Inflows	59,427	21,290	20,294	2,597	10,366	1,708	3,172
Future Production Costs	33,180	14,480	12,306	1,702	3,160	688	844
Future Development Costs	5,384	1,170	2,563	41	433	107	1,070
Future Dismantlement and Site Restoration Costs, Net	1,660	166	189	246	541	391	127
Future Income Tax	3,727	249	238	28	3,017	–	195
Future Net Cash Flows	15,476	5,225	4,998	580	3,215	522	936
10% Discount Factor	9,183	4,217	3,633	24	725	95	489
Standardized Measure	**6,293**	**1,008**	**1,365**	**556**	**2,490**	**427**	**447**
December 31, 2008							
Future Cash Inflows	25,305	–	9,276	2,984	8,753	1,809	2,483
Future Production Costs	10,847	–	5,013	1,606	2,616	765	847
Future Development Costs	3,008	–	1,350	138	564	33	923
Future Dismantlement and Site Restoration Costs, Net	1,421	–	89	243	558	446	85
Future Income Tax	2,653	–	–	–	2,467	–	186
Future Net Cash Flows	7,376	–	2,824	997	2,548	565	442
10% Discount Factor	2,953	–	1,802	186	505	84	376
Standardized Measure	**4,423**	–	**1,022**	**811**	**2,043**	**481**	**66**

1 *Standardized measure amounts in 2008 reflect bitumen production activities only; 2010 and 2009 amounts reflect upgrading activities to produce synthetic barrels.*

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	**2010**	**2009**	**2008**
Beginning of Year	6,293	4,423	11,129
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(3,018)	(2,306)	(4,387)
Net Changes in Prices and Production Costs Related to Future Production	3,364	561	(9,756)
Extensions, Discoveries and Improved Recovery, Less Related Costs	373	884	376
Changes in Estimated Future Development and Dismantlement Costs	(580)	(306)	(676)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	782	1,091	1,343
Revisions of Previous Quantity Estimates	1,245	607	615
Accretion of Discount	901	655	1,730
Purchases of Reserves in Place	51	330	–
Sales of Reserves in Place	(301)	(2)	–
Net Change in Income Taxes	(645)	(596)	4,049
	8,465	**5,341**	**4,423**
Inclusion of Syncrude as Oil and Gas Activity	–	1,008	–
Conversion of Insitu Bitumen to Synthetic Reserves	–	(56)	–
End of Year	**8,465**	**6,293**	**4,423**

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2011 Management Proxy Circular
Outlines Nexen's corporate governance practices, including our approaches to executive compensation and shareholder engagement.

Sustainability Report
Summarizes Nexen's way of doing business, including our approach to health and safety, the environment and social responsibility.

Corporate Profile
Provides an overview of Nexen's assets and strategies, how we create value and how we work. Available in Spring 2011.

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